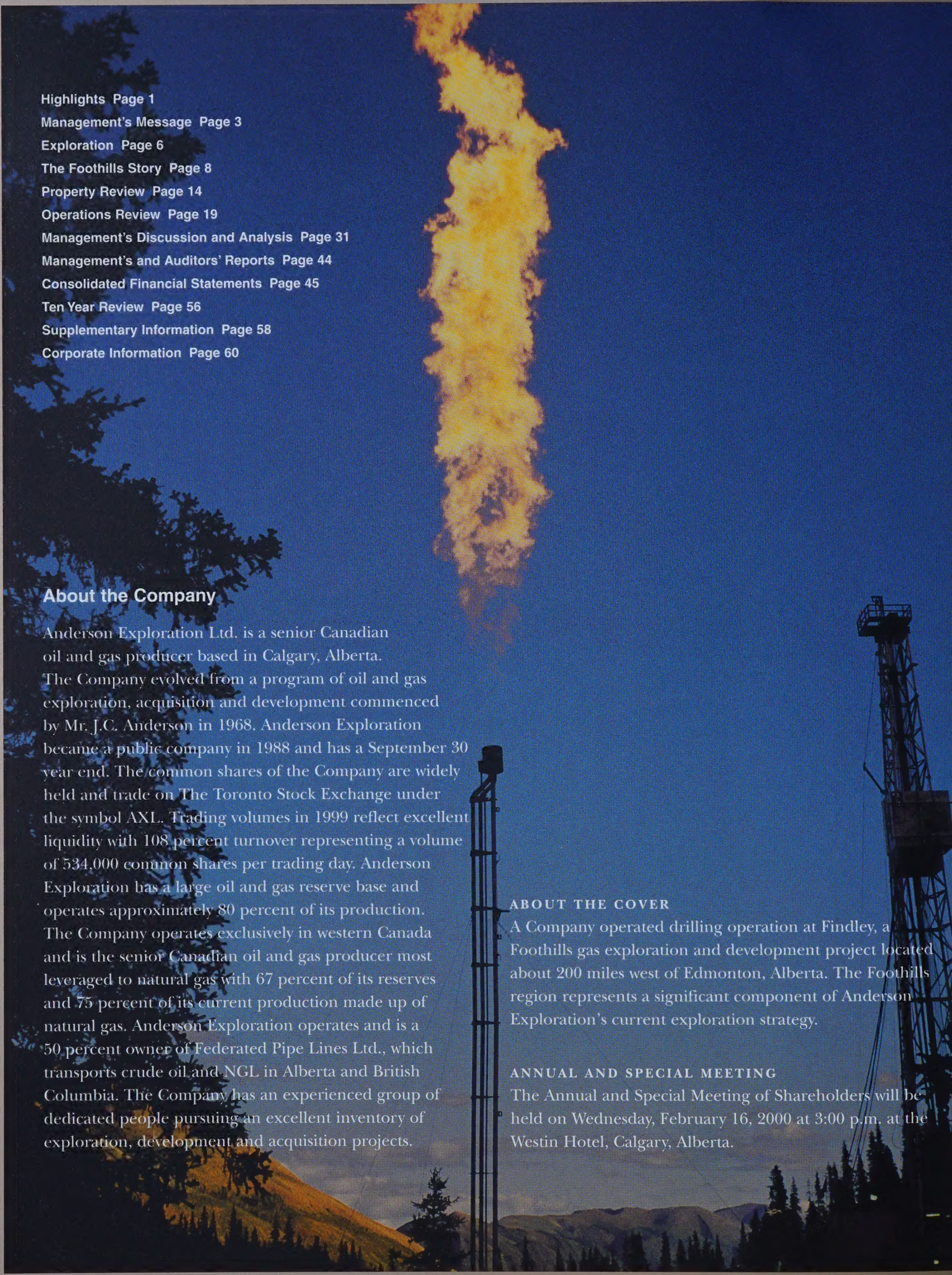
1999 ANNUAL REPORT

ANDERSON EXPLORATION LTD.



About the Company

Anderson Exploration Ltd. is a senior Canadian oil and gas producer based in Calgary, Alberta. The Company evolved from a program of oil and gas exploration, acquisition and development commenced by Mr. J.C. Anderson in 1968. Anderson Exploration became a public company in 1988 and has a September 30 year end. The common shares of the Company are widely held and trade on The Toronto Stock Exchange under the symbol AXL. Trading volumes in 1999 reflect excellent liquidity with 108 percent turnover representing a volume of 534,000 common shares per trading day. Anderson Exploration has a large oil and gas reserve base and operates approximately 80 percent of its production. The Company operates exclusively in western Canada and is the senior Canadian oil and gas producer most leveraged to natural gas with 67 percent of its reserves and 75 percent of its current production made up of natural gas. Anderson Exploration operates and is a 50 percent owner of Federated Pipe Lines Ltd., which transports crude oil and NGL in Alberta and British Columbia. The Company has an experienced group of dedicated people pursuing an excellent inventory of exploration, development and acquisition projects.

ABOUT THE COVER

A Company operated drilling operation at Findley, a Foothills gas exploration and development project located about 200 miles west of Edmonton, Alberta. The Foothills region represents a significant component of Anderson Exploration's current exploration strategy.

ANNUAL AND SPECIAL MEETING

The Annual and Special Meeting of Shareholders will be held on Wednesday, February 16, 2000 at 3:00 p.m. at the Westin Hotel, Calgary, Alberta.

Highlights

	1999	1998	% Change
Financial (in thousands, except per share amounts)			
Total revenue	$ **799,736**	$ 683,661	17
Revenue, net of royalties	$ **673,858**	$ 575,945	17
Cash flow from operations	$ **395,610**	$ 306,037	29
Per common share (basic)	$ **3.19**	$ 2.49	28
Earnings	$ **70,398**	$ 24,606	186
Per common share (basic)	$ **0.57**	$ 0.20	185
Average common shares outstanding	**124,101**	122,794	1
Net capital expenditures	$ **289,157**	$ 527,658	(45)
Long term debt	$ **545,234**	$ 695,517	(22)
Shareholders' equity	$ **1,135,785**	$ 1,022,716	11
Operating			
Daily sales			
Natural gas (Mmcfd)	**568**	555	2
Crude oil (Bpd)	**25,565**	29,808	(14)
NGL (Bpd)	**8,020**	7,376	9
Total liquids (Bpd)	**33,585**	37,184	(10)
Average prices			
Natural gas ($/Mcf)	$ **2.48**	$ 1.94	28
Crude oil ($/Bbl)	$ **21.17**	$ 18.53	14
NGL ($/Bbl)	$ **15.82**	$ 16.61	(5)
Total liquids ($/Bbl)	$ **19.89**	$ 18.15	10
Reserves			
Natural gas (Bcf)			
Proven	**1,812**	1,758	3
Proven plus probable	**2,699**	2,675	1
Crude oil and NGL (Mbbls)			
Proven	**146,042**	148,047	(1)
Proven plus probable	**221,672**	225,570	(2)
Undeveloped land (thousands of acres)			
Gross	**5,639**	5,373	5
Net	**3,434**	3,392	1
Drilling activity (gross number of wells drilled)			
Gas wells	**179**	237	(24)
Oil wells	**46**	138	(67)
Dry holes	**48**	71	(32)
	273	446	(39)
Service wells	**3**	8	(63)
Total wells	**276**	454	(39)
Employees			
Calgary	**410**	390	5
Field	**352**	347	1

GROWTH

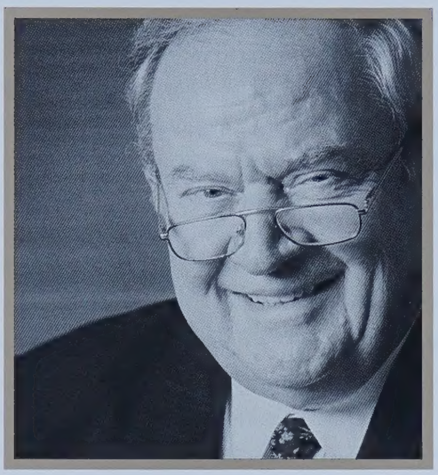
Policy Statement

Anderson Exploration is in business to make a profit.

Mission Statement

Anderson Exploration's mission is to create and continually increase shareholder value in the oil and gas exploration and production business while conducting all activities toward that end in the safest, most environmentally responsible and regulatory compliant manner possible with the highest standards of integrity.

Management's Message



J.C. ANDERSON
Chief Executive Officer

BRIAN H. DAU
Chief Operating Officer

In fiscal 1999, Anderson Exploration achieved the highest total cash flow and cash flow per share in its history, notwithstanding a difficult start to the year. At the beginning of the year, oil prices were in a free fall, and bottomed in December at a level not seen in over 15 years. In response, the Company suspended all capital expenditures on oil projects and, as a result, oil production declined year over year. However, gas prices were increasing as predicted with new export pipeline capacity coming on stream in our first quarter. As the year progressed, oil prices improved dramatically and in the last two months of the year were more than double December lows. Gas prices remained strong and for the year averaged at a level not seen since 1985. Cash flow increased 29 percent and earnings jumped 186 percent over 1998. While spending only 73 percent of our cash flow, we replaced 115 percent of our production at a finding and development cost for proven reserves that was 30 percent lower than 1998. We reduced our capital spending by 45 percent from 1998 and our future financial obligations by 19 percent, but still maintained our production on a barrel equivalent basis at the prior year's level. As a result, we enter fiscal 2000 in a strong commodity price environment with the financial capacity to pursue a strategic plan for growth in 2000 and beyond.

1999 IN REVIEW

Notwithstanding very low oil and NGL prices early in the year and a decline in liquids production, cash flow from operations increased to a record of $396 million or $3.19 per share in 1999 from $306 million or $2.49 per share in 1998. Earnings increased to $70 million or $0.57 per share from $25 million or $0.20 per share. These results demonstrate the impact that our leverage to natural gas and the improving prices for that commodity have on our financial results. In 1999, 74 percent of our product sales volumes on a barrel equivalent basis were represented by natural gas.

Natural gas prices increased 28 percent to $2.48 per thousand cubic feet in 1999 compared to $1.94 per thousand cubic feet in 1998. These are the highest natural gas prices we have seen since 1985 when the Company recorded an average price of $2.82 per thousand cubic feet. Sales volumes increased modestly to average 568 million cubic feet per day in fiscal 1999 versus 555 in 1998. We had predicted the increase in natural gas prices as a result of the start up of additional export pipeline take away capacity early in the fiscal year. Notwithstanding a warm winter in North America, this event allowed Canadian wellhead prices to approach equilibrium with the higher prices experienced in the U.S. marketplace. Total Canadian deliverability is now in balance with demand resulting in sustainable higher prices. We did not predict the turnaround in oil prices that occurred during the year and, in fact, at the beginning of the year had visualized very low prices throughout

the year. Our wellhead price bottomed in December at $14.17 per barrel trending downward. As a result, we suspended expenditures on oil projects. Unexpectedly, oil prices started to recover at the end of our second quarter but wet conditions in the field after spring breakup precluded a restart of oil drilling operations until late in the year. As a result, our 1999 oil sales volumes decreased 14 percent from 1998 to 25,565 barrels per day. NGL volumes increased during the year with the net effect being a 10 percent decline in liquids volumes to 33,585 barrels per day.

Anderson Exploration's 1999 net capital expenditures were 45 percent lower than in 1998 at $289 million. The Company underspent its revised capital budget of $345 million because of the suspension of expenditures on oil projects early in the year due to low prices and the slow startup of drilling operations after spring breakup. We replaced 115 percent of annual production with proven reserves and spent only 73 percent of cash flow from operations. This was accomplished at a unit finding and development cost of $5.31 per barrel of oil equivalent for proven reserves converting gas to oil at six thousand cubic feet per barrel, a 30 percent improvement over fiscal 1998. The controlled capital expenditure program permitted a $132 million improvement in our balance sheet in the form of reduced debt and working capital deficiency. The Company's trailing long term debt to cash flow ratio dropped from 2.3 to 1.4 at year end.

PEOPLE

Fiscal 1999 brought several changes in the management team of Anderson Exploration. Larry Macdonald, President and Chief Operating Officer and Alan Archibald, Vice President, Operations left the Company. We thank them for their contributions to Anderson Exploration. As a result, our succession plan was activated. Brian Dau was promoted to Executive Vice President and Chief Operating Officer after 12 years of service with the Company. Drew Livingston was promoted to Vice President, Production. Three gentlemen were promoted to Department Heads in the Calgary Office. Phil Harvey was promoted to Manager, Exploitation, Kevin Stashin to Manager, Operations and Sam Coles to Manager, Business Development. Two new directors have been nominated for election by the shareholders at the Annual Meeting in February 2000. Mr. Tim Swinton is a Calgary businessman with significant experience in the oilfield service business and Mr. Tom Davidson is an American, formerly a resident of Toronto, Ontario, who has had a varied business career in Canada and the United States.

FISCAL 2000 CAPITAL BUDGET

The capital expenditure budget for fiscal 2000, originally established in August 1999 at $470 million, has now been increased to $565 million. Exploration and land expenditures will nearly double from 1999 to $250 million in order to pursue prospects that have been developed over the past few years. The budget contemplates drilling 19 net wells to depths of 10,000 to 15,000 feet searching for gas. While about three quarters of total expenditures are directed toward gas projects, oil projects will attract about three times the 1999 spending level because of substantially improved prices. The budget will essentially be funded by cash flow with any acquisition opportunities financed using the Company's excellent balance sheet.

STRATEGIC PLAN

Given our Policy and Mission statements set out on the page facing the beginning of this message, our overall goal must be to grow our production and reserves in such a manner that we increase shareholder value. Some of the goals, targets and elements of our strategic plan are to (1) remain a low cost, efficient operator, (2) maintain a superior balance sheet, (3) fund "ordinary course" capital expenditures within cash flow, (4) assure equity financed projects are accretive on a per share basis and (5) encourage technical excellence in our staff. Our exploration strategy is to dedicate a minimum of one third of our ordinary course capital expenditures to

exploration, shifting our major emphasis in western Canada to the deep Alberta Basin, the Foothills, northeast British Columbia and the southern Territories, while continuing a program in our more traditional areas. As well, we are expanding our exploration efforts to newly acquired lands in the northern Yukon and the Mackenzie Delta and will examine the merits of other basins in Canada in order to accommodate growth in the future. Our strategic commodity emphasis in North America will be on gas but not to the exclusion of good oil projects. Our heavy oil business in Canada will be expanded over time. We will examine opportunities in the United States and overseas that we generate or are presented to us, but will not rush into these arenas at this time.

OUTLOOK

We are entering fiscal 2000 in a very strong commodity price environment. We have not seen oil and natural gas prices at their current levels since 1985. Our view on natural gas prices was well documented in last year's Annual Report and other communications. As predicted, with the new export pipeline capacity that came on stream just a year ago, gas prices responded very favourably. We are often asked if these prices are sustainable. We think they are for the foreseeable future. More export pipeline capacity is on the way with the completion of the Alliance Pipeline a year from now. The downstream market will need the gas, but will the Canadian industry be able to fill all of the local and takeaway pipeline capacity? It will be difficult but that will have a positive effect on prices. Total U.S. production is, at best, flat year over year and notwithstanding the very warm start to the heating season, demand for Canadian gas is there and prices so far this winter are excellent. We look for strong gas prices to prevail throughout the year with an improvement in our average price over the 1999 value.

The current oil price is a pleasant surprise to us. A year ago, the West Texas Intermediate price bottomed at $US11.31 per barrel. Last month, the price averaged above $US25.00. Discipline by major oil producing countries in maintaining production cuts to balance rising demand is the reason. We expect oil prices to remain relatively strong throughout our fiscal year and certainly not return to year ago levels. As a result, we have restarted significant oil development and exploration work. We will have a busy exploration year with our emphasis on gas in the deeper part of the basin in Alberta, the Foothills and northeast British Columbia. As well, we are planning seismic surveys on our newly acquired exploration acreage on the Mackenzie Delta and Eagle Plains in the northern Yukon.

Our balance sheet is strong, permitting us to participate in acquisitions when we develop suitable opportunities. We have received the approval of The Toronto Stock Exchange for a normal course issuer bid permitting us to buy back up to five percent of our common shares in the period from December 1, 1999 to November 30, 2000. This process has already started. Our increased exploration activity and our leverage to natural gas should serve us well. Given continued strength in commodity prices, we should see record cash flow and earnings in fiscal 2000. Our prospects have never been better.

We take this opportunity to thank our employees for their exemplary performance in 1999. We expect that they will perform every bit as well in the current year which should be very busy as we enter the new millennium. Be assured, we appreciate the support of you, our shareholders.

J.C. Anderson

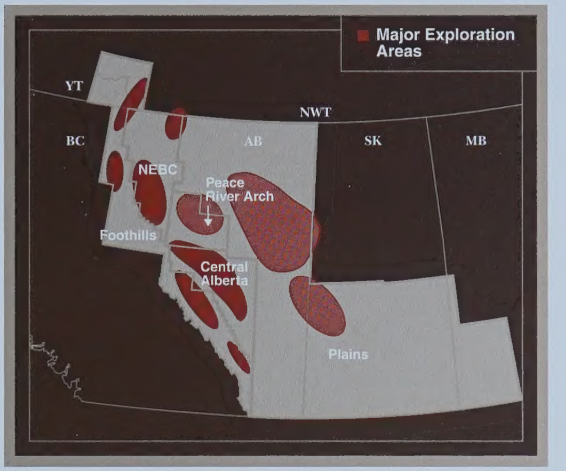
J.C. Anderson
Chairman & Chief Executive Officer

Brian H. Dau
Executive Vice President & Chief Operating Officer

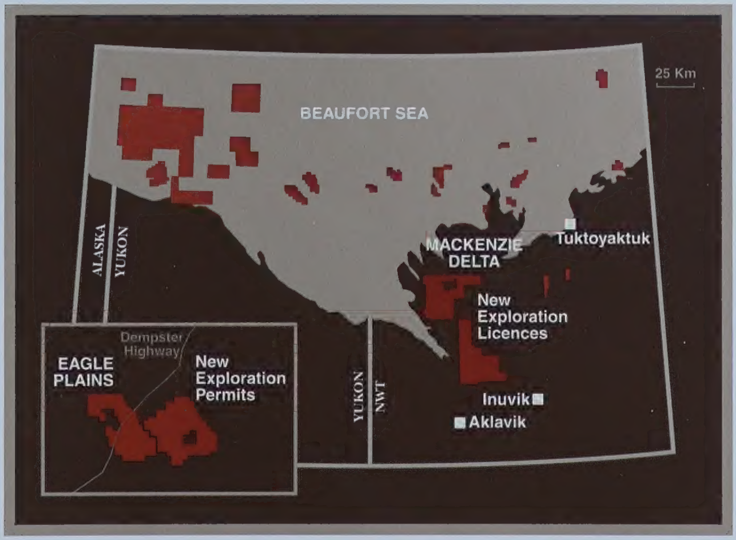
January 4, 2000

EXPLORATION

Exploration has always played an important part in the growth of the Company. Anderson Exploration owes most of its early growth to a major exploratory gas discovery in 1970 at Dunvegan in the Peace River Arch region of Alberta. Up until recently, the Company's major exploration efforts were concentrated in the Peace River Arch area and in east central Alberta around Lloydminster. The acquisition of Columbia Gas in 1992 and the Home Oil merger in 1995 brought the Company meaningful exploration exposure to other areas, notably, northeastern Alberta, the deeper part of the Alberta basin, the Foothills and northeast British Columbia. In its early history, the Company relied on subsurface geology and well information evaluation with heavy emphasis on petrophysics and only sporadic use of geophysics. Beginning in the mid 1980s, the Company began increasing its use of seismic and today uses it extensively to supplement its subsurface and petrophysical work. The Home merger provided an extensive inventory of seismic data such that the Company now has about 80,000 line miles of proprietary data, about 100,000 line miles of trade data and over 1,500 square miles of 3D data in house. Without a doubt, this data, combined with advanced technology, is a valuable exploratory resource. The Company's fiscal 2000 budget contemplates expenditures of $33 million for the acquisition of new seismic data.



In the past few years, the Company has shifted its major exploration emphasis to northeast British Columbia, the Foothills along the entire mountain front as far north as the southern territories and the deeper part of the basin in south central Alberta. The targets in these areas offer higher reserve potential but also carry higher risks. Recent improvements in drilling and seismic technology, however, permit better management of risk particularly in the deeper parts of the basin and the Foothills. The prospects in these areas are heavily weighted toward gas. In fiscal 2000, the budget contemplates drilling 19 net wells on gas prospects to depths from 10,000 to 15,000 feet. For the longer term, Anderson Exploration has acquired a 40 percent interest in two large Exploration Licences totalling 365,000 gross acres on the Mackenzie Delta to complement interests in Significant Discovery Licences already held there through a subsidiary. As well, a 100 percent interest has been acquired in two large Exploration Permits totalling 198,000 acres in the Eagle Plains area in the northern Yukon. These areas are gas prone and Anderson Exploration foresees the demand for gas from areas such as these in the North American market early in the new millennium. The Company's philosophy is that exploration should be funded only out of cash flow. With the positive outlook for commodity prices, a very substantial exploration program is contemplated given a strategy of dedicating a minimum of one third of annual capital expenditures to exploration over the next few years.



EXPLORATION

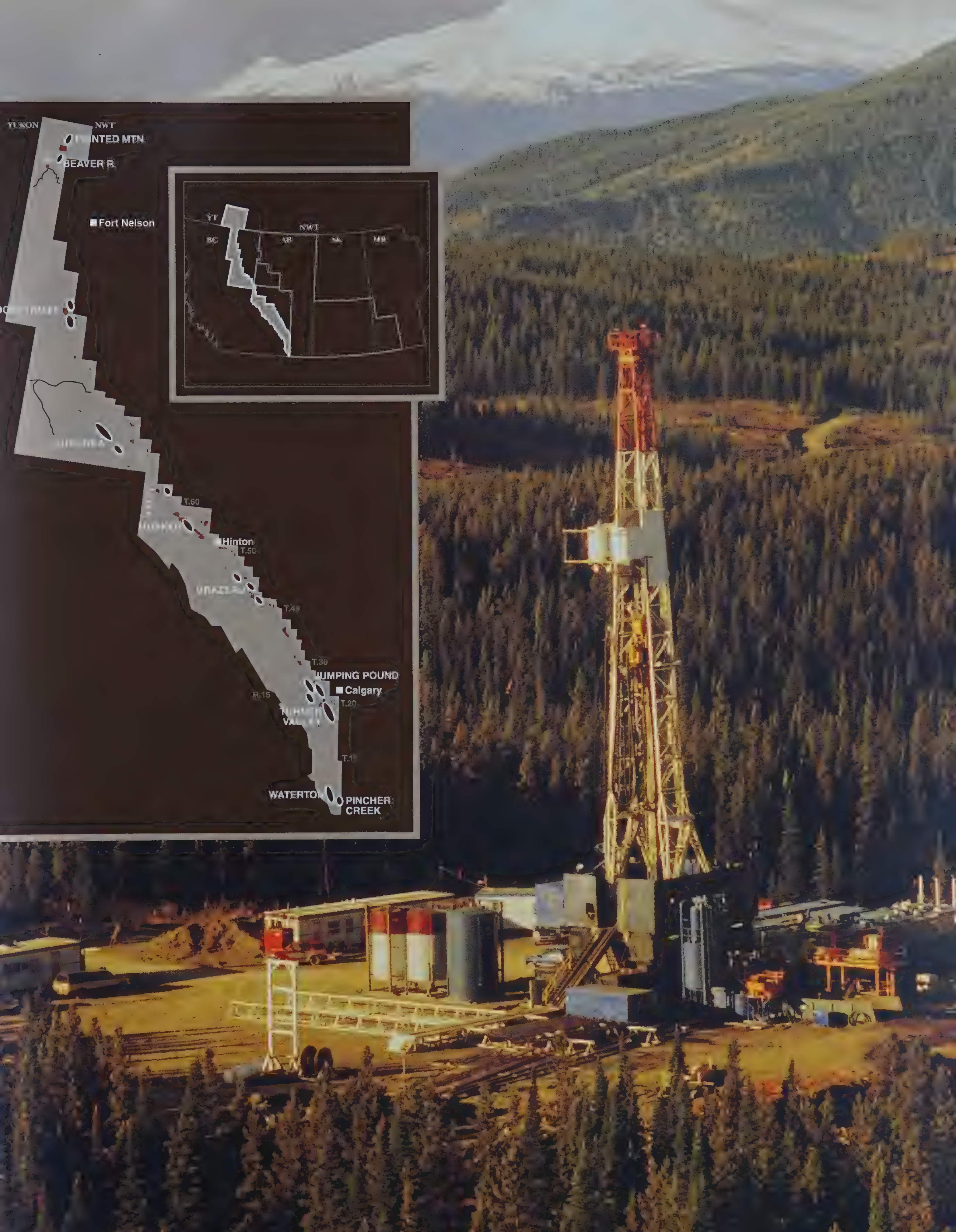
The Foothills Story – History

THE BEGINNING

The Foothills of the Western Canada Sedimentary Basin is a belt of rolling hills and mountainous terrain located on the eastern slopes of the Rocky Mountains. It extends for about 1,100 miles from the 49th parallel north to the Liard Plateau in the southern Northwest Territories. The surface terrain generally reflects the subsurface, where rocks ranging from Cambrian to Cretaceous in age were thrusted and folded during a mountain building period called the Laramide, that ended some 60 million years ago. This event resulted in the formation of traps that contain large quantities of hydrocarbons, primarily natural gas in Mississippian and Devonian age rocks.

HISTORY The history of oil and gas exploration in the Foothills dates back to a time when surface geology was used almost exclusively as an indicator for subsurface structures. Seismic data was not available to map the subsurface, so explorationists located their drilling targets by mapping the surface expression of subsurface features. The Turner Valley area immediately southwest of Calgary was one place where early explorationists could ply their trade. This area was easily accessible with good exposed and expressive surface geology. The oil and gas industry in Alberta and the Foothills took a significant step at Turner Valley in 1924. The Royalite No. 4 well encountered Mississippian “Lime” at 3,740 feet that flowed at a rate of 21 million cubic feet of gas per day. This started a rush of drilling in the Turner Valley area, which continued into the 1940s, and saw the birth of many oil and gas companies including Home Oil, now a subsidiary of Anderson Exploration. The Turner Valley field continues to produce oil and gas today.

The introduction of seismic reflection technology in the 1940s provided a new tool for exploration in the Foothills. Explorationists began to expand on the Turner Valley success, and exploration pushed north and south to Pincher Creek, Jumping Pound, Brazeau and Muskeg. Major discoveries at Jumping Pound in 1944 and at Pincher Creek in 1948 signalled the birth of the Foothills as a major exploration area in western Canada. Foothills exploration efforts were focused in southern Alberta in the 1950s and early 1960s. The Waterton discovery in 1957 was the largest gas field discovered to date in the Foothills, with 4.7 trillion cubic feet of raw gas in place in Devonian and Mississippian reservoirs resulting in reserves of about 2.5 trillion cubic feet of marketable gas. Later, Foothills exploration proceeded into British Columbia, the Yukon and the Northwest Territories. Major gas discoveries in the Mississippian Debolt at Pocketknife and the middle Devonian Nahanni at Beaver River in 1959 and the Triassic Baldonnel at Sukunka in 1964 in British Columbia, and the Nahanni at Pointed Mountain in 1966 in the Northwest Territories demonstrated the gas potential of the entire Foothills belt.


YUKON
NWT
BEAVER R.
Fort Nelson
YT
NWT
BC
AB
SK
MB
T.60
Hinton
T.50
T.40
T.30
Calgary
R.15
T.20
PINCHER CREEK

EXPLORATION

The Foothills Story – Geology

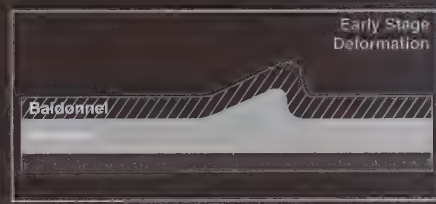
THE CHALLENGE

SCHEMATIC FOOTHILLS CROSS-SECTION

GEOLOGY The primary targets for Foothills exploration have been Mississippian and Devonian carbonates in south and west central Alberta, Triassic and Mississippian carbonates in British Columbia and Middle Devonian carbonates in far northeast British Columbia and the southern Yukon and Northwest Territories. Drilling depths for Mississippian and Devonian targets generally range between 8,000 and 16,000 feet. Additional shallower targets are Cretaceous and Jurassic sandstones draped over deep structures or themselves thrusted at the edge of the Foothills belt.

The key to successful exploration in the Foothills is the location of fracture development in reservoir rock. Typically, the matrix rock has very low porosity and permeability, permitting only low and uneconomic gas producing rates. During the folding process, the reservoir rocks were fractured, providing high permeability conduits connecting zones with effective matrix porosity. This allows productive zones to produce at high flow rates, a necessity because of the high cost of Foothills exploration. It is important to acquire good quality seismic data in order to develop a structural model which predicts where the highest concentrations of fractures exist. Generally, these exist at points of maximum folding or flexure.

FAULT-BEND FOLDING
(Southern Alberta)



DETACHMENT FOLDING
(British Columbia)

FRACTURING

The Foothills Story – Findley

THE POTENTIAL

ANDERSON EXPLORATION IN THE FOOTHILLS In 1929, the Home Oil No. 1 well at Turner Valley encountered flows of 22 million cubic feet per day and 600 barrels of condensate per day. Anderson Exploration acquired Home Oil in 1995 and now operates Turner Valley Unit No. 6, which has produced 52.5 million barrels of oil and 289 billion cubic feet of gas. In 1992, the Columbia Gas acquisition brought Anderson Exploration operatorship of the Kotaneelee field, a major Foothills structure in the Yukon. Until 1998, the Company's Foothills activity focused mainly on production at Turner Valley, Moose Mountain, Sarcee and Kotaneelee. Anderson Exploration successfully increased its working interest in dormant Home Oil properties at Findley and Narraway and acquired additional high working interest landholdings in these areas. These properties, originally drilled in the late 1970s for deep Triassic and Mississippian targets, were proved to have significant gas potential in the overlying sandstones of Cretaceous and Jurassic age.

Anderson Exploration is taking an aggressive approach to Foothills exploration and has assembled a team of seasoned professionals with abundant Foothills exploration experience. In addition to Findley and Narraway, the Company increased landholdings at Stolberg and Burnt Timber in Alberta and added a new area, Chicken Creek in British Columbia. Exploration success has been experienced at Findley, Chicken Creek and Fort Liard in the Northwest Territories.

THE FINDLEY AREA Findley offers an example of the Company's success in the Foothills. The structure was originally drilled in 1947. Sour gas was discovered but was of no economic value. In 1975, a well drilled by others flowed gas at rates in excess of 10 million cubic feet per day, but subsequent drilling in 1978 had discouraging results. Anderson Exploration undertook a detailed geological, geophysical and engineering review of the field which revealed significant gas potential in the shallower Cretaceous and Jurassic sections above the main gas bearing intervals previously tested. In March 1999, an old well was completed and put on production at a rate of 22 million cubic feet per day of raw gas. Anderson Exploration obtained operatorship of the field and initiated an aggressive exploration and development program. Five wells have been drilled and significant high flow rate gas potential has been discovered in the sands of Cretaceous and Jurassic age. Fiscal 2000 activity includes the expansion of existing production facilities, the tie in of existing wells, the completion of a 3D seismic survey and the drilling of additional wells.


R.7
R.6
R.5 W6M

Property Review

Anderson Exploration's current western Canadian operations are divided into five main regions of exploration and development activity based on geology and geography. These regions stretch from the southeast tip of the Yukon Territory to Manitoba. They present the opportunity to participate in most types of geological plays and produce all types of hydrocarbons. The Company has shifted a significant component of its exploration focus over the last few years to the less explored areas of the Foothills, the deeper part of the basin in central Alberta and to northeast British Columbia. The Peace River Arch and Plains regions continue to provide the Company with significant exploration and development opportunities to sustain production and cash flow in those areas. Land, exploration and exploitation staff work as teams to identify and develop opportunities in each of these regions.

1999 Activity and Results
- Sales – 31 Mmcfd and 949 Bpd
- Acquired 29,173 net undeveloped acres
- Hold 145,306 net undeveloped acres in region
- Drilled 8 gross (5 net) wells, resulting in 7 gas wells and 1 service well
- Farmed in a 23,000 acre block at Chicken Creek, re-drilled an existing well and made a gas discovery
- Two new wells at Findley tested at rates from 6 to 18 Mmcfd from multiple reservoirs
- Participated with a 4.1 percent interest in the Fort Liard K-29 well in the NWT which flowed at 70 Mmcfd of raw gas

2000 Planned Activity
- Drill 16 gross (9 net) exploration wells and 4 gross (2 net) development wells
- New exploration drilling at Narraway, Stolberg and Burnt Timber and further drilling at Cabin Creek, Findley, Fort Liard and Chicken Creek
- Tie in Chicken Creek gas discovery
- Major 3D seismic program at Findley

FOOTHILLS
Ron Lambie, Area Exploration Manager
Scot Collins, Area Exploitation Manager
Ron Newborn, Senior Landman

CENTRAL ALBERTA
Peter Parkinson, Senior Landman
Brian Kergan, Area Exploitation Manager
George Clease, Senior Landman
Tim Watters, Area Exploration Manager

NE BRITISH COLUMBIA
Steve Babcock, Area Exploration Manager
Les Hogan, Senior Landman
Will Yakymyshyn, Area Exploitation Coordinator

CENTRAL ALBERTA

1999 Activity and Results
- Sales – 75 Mmcfd and 10,000 Bpd
- Acquired 63,889 net undeveloped acres
- Hold 224,692 net undeveloped acres in region
- Drilled 40 gross (16 net) wells, resulting in 34 gas wells, 1 oil well and 5 dry holes
- Success at Wapiti/Karr added 9 Mmcfd and 110 Bpd
- Exploration and development at Harmattan added 5 Mmcfd and 145 Bpd

2000 Planned Activity
- Drill 30 gross (19 net) exploration wells and 41 gross (14 net) development wells
- Exploration drilling program in the deep basin
- Exploration drilling at Wapiti/Bilbo, Karr/Simonette and Harmattan
- Miscible flood expansion at Swan Hills

NE BRITISH COLUMBIA

1999 Activity and Results
- Sales – 98 Mmcfd and 6,217 Bpd
- Acquired 60,141 net undeveloped acres
- Hold 591,402 net undeveloped acres in region
- Drilled 61 gross (36 net) wells, resulting in 42 gas wells, 7 oil wells and 12 dry holes
- Drilling at Tooga and Wargen added 16 Mmcfd

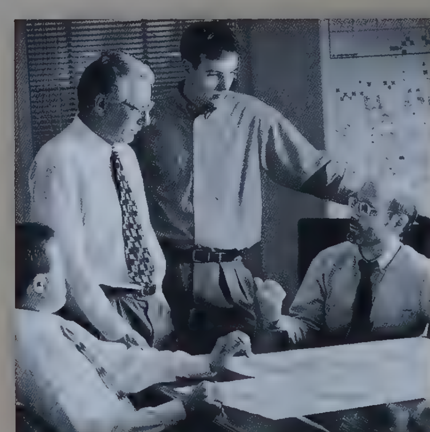
2000 Planned Activity
- Drill 58 gross (55 net) exploration wells and 24 gross (15 net) development wells
- Horizontal gas drilling program at Tooga
- Oil development at Eagle/Stoddart
- Deep exploration at Wargen

1999 Activity and Results

- Sales – 195 Mmcfd and 6,937 Bpd
- Acquired 35,040 net undeveloped acres
- Hold 724,547 net undeveloped acres in region
- Drilled 48 gross (35 net) wells, resulting in 35 gas wells, 2 oil wells, 9 dry holes and 2 service wells
- Constructed 5 Mmcfd gas plants at Fahler and Berwyn
- Dunvegan gas plant modified and tied into Federated Pipe Lines resulting in incremental ethane recovery of 735 Bpd

2000 Planned Activity

- Drill 32 gross (28 net) exploration wells and 52 gross (38 net) development wells
- New exploration drilling to target deeper Devonian prospects
- Construct new sour gas plant with acid gas injection at Culp



PEACE RIVER ARCH
Craig Thomas, Landman
Greg Kuran, Area Exploitation Manager
Kevin Rosamond, Landman
Al Onia, Area Exploration Manager

1999 Activity and Results
- Sales – 170 Mmcfd and 9,482 Bpd
- Acquired 59,822 net undeveloped acres
- Hold 1,404,564 net undeveloped acres in region
- Drilled 119 gross (88 net) wells, resulting in 61 gas wells, 36 oil wells and 22 dry holes

2000 Planned Activity
- Drill 104 gross (102 net) exploration wells and 146 gross (122 net) development wells
- Exploration and exploitation activities will continue in core areas

1999 Activity and Results
- Seismic and drilling programs at Woodenhouse, Leismer, Marten Hills and Mistahae
- 16 Mmcfd added at Woodenhouse and 12 Mmcfd added at Leismer/Kirby

2000 Planned Activity
- New exploration drilling planned for Liege, Woodenhouse and Bat Lake
- New seismic to be acquired at Woodenhouse, Marten Hills and Liege

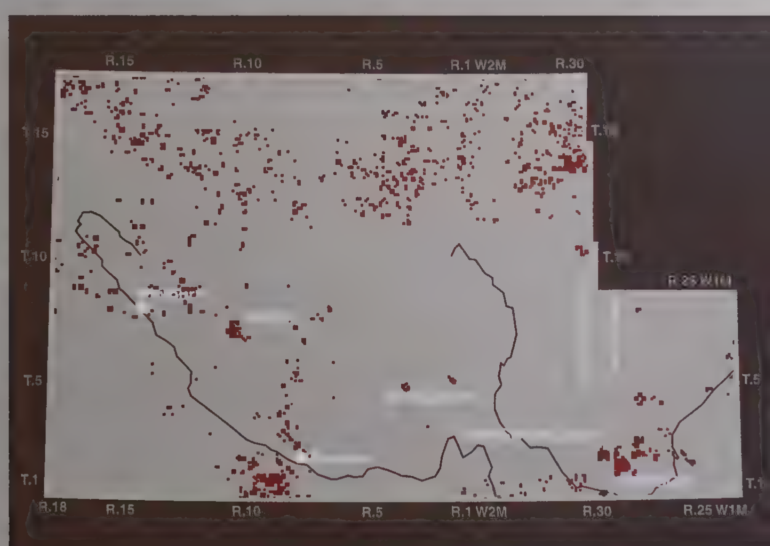
1999 Activity and Results
- Resumed heavy oil drilling at Marwayne and Edam
- Increased natural gas production by 4 Mmcfd

2000 Planned Activity
- Drill 96 heavy oil exploration and development wells
- Development opportunities for shallow gas at John Lake

1999 Activity and Results
- Drilled one operated development well at Innes
- Acquired a 3D seismic survey at Steelman

2000 Planned Activity
- New exploration drilling at Steelman

PLAINS AREA
Brock Young, Landman
Paul Vigneau, Area Exploitation Manager
Frank Gratton, Area Exploration Manager



[illegible] Cole, Manager, Business Development
Dan Kell, Vice President, Land
Richard Osborne, Vice President, Pipelines

Henry Assen, Vice President, Marketing
Kevin Stashin, Manager, Operations
Phil Harvey, Manager, Exploitation

Fred Baker, Vice President, Exploration
Drew Livingston, Vice President, Production

OPERATIONS

While spending only 73 percent of cash flow from operations on capital expenditures, we replaced 115 percent of annual production with proven reserves. The controlled capital expenditure program strengthened our balance sheet and will permit future growth through exploration and acquisitions.

Operations Review

LAND

Anderson Exploration's undeveloped land inventory in the western provinces remained relatively flat in 1999 at 3,081,000 net acres. This undeveloped land base is located 63 percent in Alberta, 20 percent in British Columbia, 16 percent in Saskatchewan and one percent in Manitoba. The average working interest in the land base is 78 percent. In addition to the western provinces, Anderson Exploration increased its net undeveloped land inventory in the Frontier regions by 69 percent to 353,000 net acres by acquiring 146,110 net acres in two Exploration Licences on the Mackenzie Delta of the Northwest Territories. Land activity in 1999 resulted in a slight increase in the Company's total undeveloped land inventory when compared to the previous year.

Industry activity at Crown land sales was down again in 1999 when compared to 1998. In the four western provinces for the year ending September 30, 1999, $622 million was spent by industry in total bonus payments to acquire 10 million acres of petroleum and natural gas rights, excluding oil sands rights, compared to $899 million for 11.3 million acres in the previous year. This represents a 31 percent reduction in Crown sale expenditures and a 12 percent reduction in total acreage sold. This reduction in total activity can be attributed largely to the decline in the price of oil early in the year. In the gas prone areas of Alberta and British Columbia where over 99 percent of the Company's Crown land expenditures were made, competition remained intense. The Company's total expenditures and price paid per acre increased 37 percent and 13 percent, respectively, in support of our aggressive exploration program. As a result, the Company purchased 20 percent more acreage than in 1998. In fiscal 2000, Anderson Exploration will continue to be active at Crown sales in support of its exploration and development programs.

SUMMARY OF UNDEVELOPED LAND HOLDINGS

At September 30	1999		1998	
(working interest lands, thousands of acres)	**Gross**	**Net**	Gross	Net
Western provinces	**3,968**	**3,081**	4,059	3,183
Frontier/other	**1,671**	**353**	1,314	209
Total	**5,639**	**3,434**	5,373	3,392

CROWN SALE LAND ACQUISITIONS

Years ended September 30	1999	1998
Expenditures ($000s)	**$ 31,749**	$ 23,228
Net acres acquired*	**394,175**	205,464
Price per acre	**$ 128**	$ 113

* Includes 146,110 net acres acquired in 1999 on the Mackenzie Delta on a work commitment basis. The Mackenzie Delta acreage is not included in the price per acre calculation.

DRILLING

Anderson Exploration participated in drilling 276 wells in 1999. This represents a 39 percent reduction in activity from the prior year, largely a reflection of depressed oil prices early in the year. The average working interest in wells drilled was 65 percent in 1999 compared to 63 percent in 1998. Expenditures for the drilling, completion and recompletion of wells in 1999 were $121 million versus $212 million in the prior year. Of these expenditures, 32 percent were directed to deep targets in the central Alberta and Foothills regions and 25 percent were incurred in northeast British Columbia. The Company's traditional producing regions in the Peace River Arch and Plains accounted for 24 percent and 19 percent of expenditures, respectively.

The Company participated in 177 development wells, 94 percent of which were cased as potential gas or oil wells. Three quarters of the successful development wells were gas wells. Significant oil development occurred only in the fourth quarter with the recovery of oil prices. The Company participated in 96 exploration wells, 61 percent of which were cased as gas or oil wells. More than 90 percent of the successful exploration wells were gas.

In light of favourable product prices and a considerable prospect inventory, the Company expects to participate in over 500 gross wells in fiscal 2000 and has contracted the drilling rigs to do so. Average drilling depths for exploratory wells are expected to increase to over 5,500 feet as the Company continues to pursue deeper targets. The fiscal 2000 budget provides for drilling 19 net wells to depths in excess of 10,000 feet.

SUMMARY OF WELLS DRILLED

Years ended September 30	1999		1998	
(number of wells)	**Gross**	**Net**	Gross	Net
Gas wells	**179**	**103**	237	149
Oil wells	**46**	**35**	138	85
Dry holes	**48**	**41**	71	46
	273	**179**	446	280
Service wells	**3**	**1**	8	4
Total	**276**	**180**	454	284

CONSTRUCTION

In 1999, Anderson Exploration spent $75 million on the construction of field gathering systems and production facilities. Most of the construction activity was focused in northeast Alberta and northeast British Columbia. In northeast Alberta, 24 wells were tied in and eight compressors were installed. This development added about 26 million cubic feet per day of gas handling capacity to the area. In northeast British Columbia, seven wells were tied in at Wargen and the gas battery was increased to 24 million cubic feet per day of capacity. In a promising new area in northeast British Columbia called Tooga, three wells with combined stabilized production of five million cubic feet per day were tied into an existing midstream facility. Further development is planned at Tooga for the winter of 2000. Near Fort St. John, two new gas batteries, having a combined capacity of about 11 million cubic feet per day, were completed at Cecil and Eagle.

Expansion of existing gathering systems continued in the Peace River Arch area. Additional compression was added to the North Cecil gas plant and two new five million cubic feet per day gas plants were constructed at Falher and Berwyn. Compression was added at Belloy and numerous well tie ins were completed. The increased Belloy capacity was connected to the Company's Dunvegan gas plant through a pipeline bored under the Peace River in 1998. This new system will allow Anderson to maximize use of its existing deep cut facilities at Dunvegan.

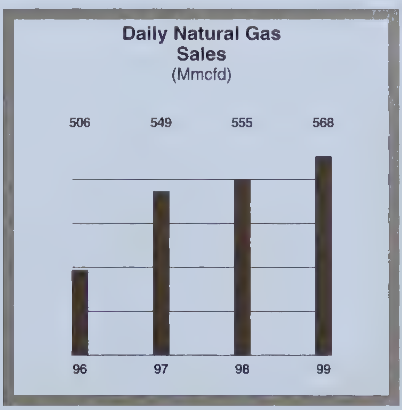
Construction activity levels increased considerably in the latter part of fiscal 1999 and the trend will continue into fiscal 2000 with new facilities being installed throughout the Company's operations.

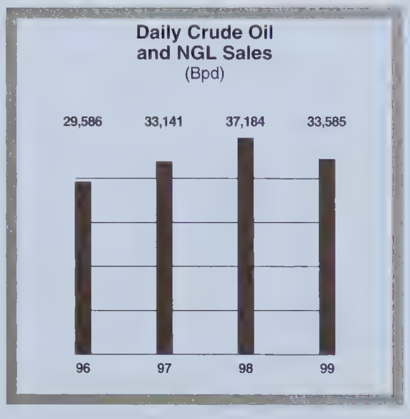
PRODUCTION/SALES

Natural gas sales increased to 568 million cubic feet per day in fiscal 1999 from 555 million cubic feet per day in 1998. Significant increases in sales were experienced at Blackstone in central Alberta, Cecil Royce in the Peace River Arch and Kotaneelee in the Yukon Territory following successful exploration and development work. Continued development and optimization activities at Wargen in northeast British Columbia and at Belloy in the Peace River Arch also resulted in increased sales. These increases were offset by declining sales in other fields. In addition, gas sales were reduced by eight million cubic feet per day on an annualized basis as a result of two unusual service interruptions in the third quarter on the Nova pipeline system in the Peace River Arch. Sales in the fourth quarter averaged 584 million cubic feet per day, up five percent from the same period in 1998.

Crude oil sales averaged 25,565 barrels per day in 1999, a decrease of 14 percent from last year. Low oil prices during the first part of the fiscal year resulted in the postponement of a large number of oil drilling and production optimization projects. Prices started to recover after spring breakup but projects were delayed further due to extremely wet weather conditions.

NGL sales increased by nine percent to 8,020 barrels per day, primarily as a result of the start up of the deep cut facilities at the Dunvegan plant in the Peace River Arch area and higher natural gas liquids yields at the Westcoast Highway gas plant in northeast British Columbia.





DAILY NATURAL GAS SALES

Years ended September 30 (Mmcfd)	1999	1998
Leismer/Kirby	**56.2**	61.2
Dunvegan	**54.4**	62.2
Birley/Wargen	**36.1**	32.3
Woodenhouse	**21.7**	19.5
Blackstone	**19.8**	14.8
Belloy	**19.5**	16.6
Cecil Royce	**18.7**	6.5
Ring Border	**17.0**	16.7
Eaglesham/Culp	**16.4**	17.0
Kotaneelee	**15.8**	9.3
Hines Creek	**14.7**	16.3
Peggo/Pesh/Tooga	**13.5**	13.2
Harmattan	**11.9**	11.9
Mistahae	**11.5**	13.1
Pembina/Brazeau	**11.0**	13.7
Normandville	**10.8**	12.4
Puskwaskau	**10.8**	8.4
Wapiti/Karr	**10.6**	8.7
Marten Hills	**10.4**	9.3
Eagle	**10.4**	6.2
Other and Royalty	**176.5**	185.2
Total	**567.7**	554.5

DAILY CRUDE OIL AND NGL SALES

Years ended September 30 (Bpd)	1999	1998
Crude Oil		
Swan Hills	**5,394**	5,707
Eagle	**2,999**	2,912
Lloydminster Heavy	**2,725**	3,476
Valhalla	**1,684**	1,658
Hayter	**1,549**	2,153
Mitsue	**1,095**	1,216
Stoddart	**974**	1,057
Virginia Hills	**889**	903
Innes	**771**	1,095
Pierson	**745**	925
Gainsborough	**668**	1,127
Normandville	**565**	509
Pembina/Brazeau	**541**	882
Progress	**503**	473
Genesee/Highvale	**396**	469
Harmattan	**357**	405
Turner Valley	**344**	364
Cecil Royce	**341**	537
Red Jacket	**258**	243
Wood River/Bashaw	**250**	383
Other and Royalty	**2,517**	3,314
	25,565	29,808
NGL	**8,020**	7,376
Total	**33,585**	37,184

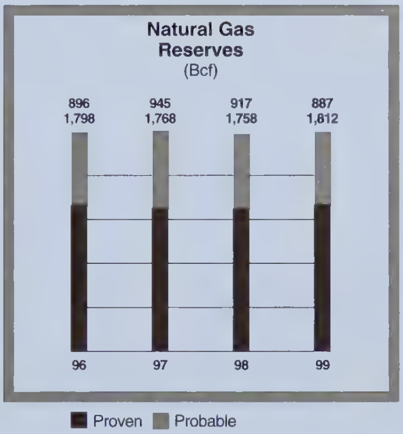
1999 QUARTERLY SALES

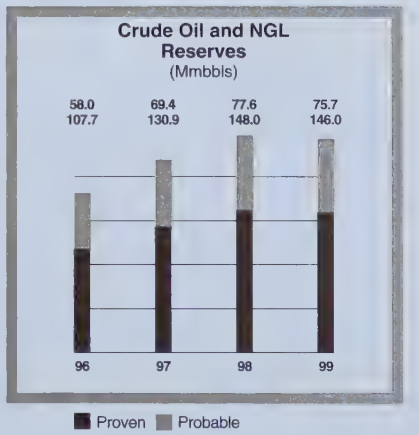
	Q1	Q2	Q3	Q4	Year
Natural gas (Mmcfd)	559	558	570	584	**568**
Crude oil (Bpd)	26,677	25,943	24,909	24,733	**25,565**
NGL (Bpd)	8,241	8,837	6,774	8,232	**8,020**
Total liquids (Bpd)	34,918	34,780	31,683	32,965	**33,585**

RESERVES

In 1999, the Company replaced 126 percent of its natural gas production and 84 percent of its crude oil and NGL production with proven reserve additions after all revisions. Before revisions, the Company added 313 billion cubic feet of proven gas reserves and 6.2 million barrels of oil and NGL reserves through drilling and net property acquisitions. Revisions reduced proven natural gas reserves by 52 billion cubic feet and increased oil and NGL reserves by 4.1 million barrels. Total proven natural gas reserves at September 30, 1999 increased three percent over last year. Total proven oil and NGL reserves were down one percent. On a barrel equivalent basis, the Company replaced 115 percent of its production with proven reserves while spending only 73 percent of its cash flow from operations.

Significant proven gas reserve additions, amounting to 45 percent of total additions, were realized at Belloy, Birley/Wargen, Findley, Leismer/Kirby and Wapiti/Karr. One half of the proven oil reserve additions were realized in the East Eagle Unit in British Columbia. The largest negative proven gas revisions were in the Company's shallow eastern Alberta gas reservoirs. In some cases, unanticipated water encroachment occurred prior to normal abandonment pressures being reached resulting in negative gas revisions of 19 billion cubic feet of proven and 48 billion cubic feet of proven plus probable gas reserves. Poor production performance in the Normandville property on the Peace River Arch resulted in negative gas revisions of 10 and 28 billion cubic feet for proven and proven plus probable gas reserves, respectively. On balance, proven liquids revisions were positive due largely to continued strong production performance in older oil fields such as Swan Hills, Valhalla and Virginia Hills, which accounted for positive proven revisions of 1.7 million barrels. Improved NGL yields at Belloy, Birley/Wargen and Harmattan resulted in upward proven revisions of 2.4 million barrels.





In 1999, the Company experienced reduced activity in the property acquisition market. The Company completed 13 gas property acquisitions at a total cost of $23 million. The Company sold 11 minor working interest properties, netting $10 million. The cost of proven reserves acquired, net of dispositions, was $3.68 per barrel of oil equivalent on a proven basis.

The Company's overall finding and development costs, after revisions, were $5.31 per barrel of oil equivalent for proven reserves and $5.66 for proven plus one half probable reserves, with gas converted to oil at six thousand cubic feet per barrel. At a conversion ratio of 10 thousand cubic feet per barrel, the comparable values were $7.85 and $8.40 per barrel of oil equivalent. These finding and development costs are based on oil and gas related expenditures of $286 million. Finding and development costs for proven reserves were 30 percent lower than the previous year and reflect the significant gas discoveries noted above as well as a more competitive service cost environment due to lower industry activity. In anticipation of a large exploration program in fiscal 2000, increased land and seismic expenditures in the fourth quarter created some offsetting upward pressure on costs.

The Company's gas reserve life indices are 8.7 years on a proven basis and 13.0 years on a proven plus probable basis. The oil and NGL reserve life indices are 11.9 years and 18.0 years for proven and proven plus probable reserves, respectively. In fiscal 1999, the Company's engineering personnel evaluated 66 percent of the proven reserves with the balance being evaluated by independent engineering consultants. In the last four years, approximately 73 percent of Anderson Exploration's reserves have been evaluated externally. The Company will continue to use independent engineering consultants to evaluate or audit a portion of its properties in fiscal 2000.

1999 RESERVE ADDITIONS AND REVISIONS

Natural Gas

(Company interest, Bcf)	Proven	Probable	Total
Drilling	297	119	416
Property acquisitions	29	30	59
Property dispositions	(13)	(4)	(17)
Total additions	313	145	458
Revisions	(52)	(175)	(227)
Sales	(207)	–	(207)
Net gain (loss)	54	(30)	24

Crude Oil and NGL

(Company interest, Mbbls)	Proven	Probable	Total
Drilling	5,267	2,820	8,087
Property acquisitions	1,012	819	1,831
Property dispositions	(128)	(343)	(471)
Total additions	6,151	3,296	9,447
Revisions	4,103	(5,189)	(1,086)
Sales	(12,259)	–	(12,259)
Net gain (loss)	(2,005)	(1,893)	(3,898)

YEAR END RESERVES – CONTINUITY TABLE

Natural Gas

(Company interest, Bcf)	Proven	Probable	Total
As at September 30, 1998	1,758	917	2,675
Additions and revisions	261	(30)	231
Sales	(207)	–	(207)
As at September 30, 1999	**1,812**	**887**	**2,699**

Crude Oil and NGL

(Company interest, Mbbls)	Proven	Probable	Total
As at September 30, 1998	148,047	77,523	225,570
Additions and revisions	10,254	(1,893)	8,361
Sales	(12,259)	–	(12,259)
As at September 30, 1999	**146,042**	**75,630**	**221,672**

MARKETING AND PRODUCT PRICES

In fiscal 1999, natural gas prices in Canada rose to their highest level since deregulation started some 14 years ago, in spite of an eight percent warmer than normal North American winter and soft U.S. prices. About 1.1 billion cubic feet per day of incremental export pipeline capacity out of Alberta provided access to higher priced markets. Recent declines in gas drilling activity have resulted in decreasing U.S. supplies of natural gas. Expansion of the U.S. economy continues to support natural gas demand growth. We expect the combination of lower supply and strong demand to provide excellent natural gas prices for the foreseeable future. With the Alliance pipeline adding another 1.3 billion cubic feet per day of export capacity in late 2000, Canadian gas prices will continue to benefit from strong U.S. prices.

Early in the year, crude oil prices hit their lowest level in a decade. Fortunately, by the end of the Company's fiscal year, crude oil prices had rebounded sharply as some of the world's major producers agreed to and actually adhered to production cuts and world oil demand gradually improved.

HISTORICAL AVERAGE COMPANY PRICES

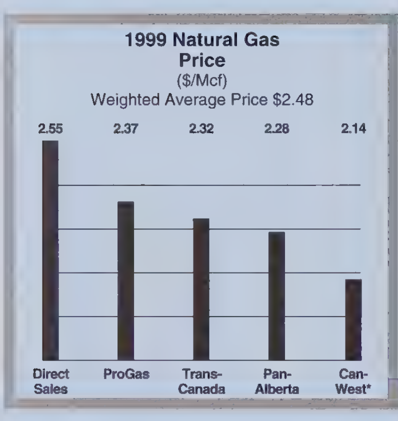
Fiscal Year	Natural Gas ($/Mcf)	Crude Oil ($/Bbl)
1985	2.82	33.76
1986	2.46	23.49
1987	1.87	21.65
1988	1.68	18.75
1989	1.65	18.49
1990	1.70	22.16
1991	1.52	24.19
1992	1.33	20.29
1993	1.67	20.66
1994	1.98	19.52
1995	1.43	22.05
1996	1.59	25.22
1997	1.91	25.37
1998	1.94	18.53
1999	**2.48**	**21.17**

Natural Gas

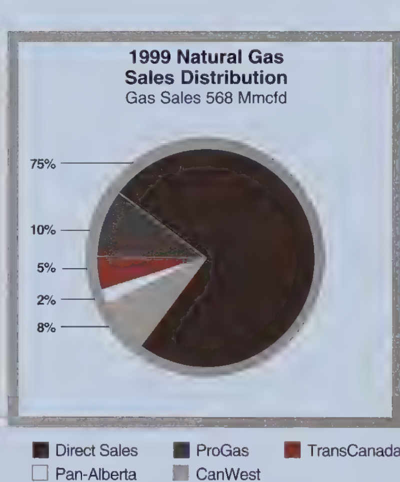
Anderson Exploration's average plant gate natural gas price improved to $2.48 per thousand cubic feet in 1999, an increase of 28 percent from 1998. After several years of bottlenecked Canadian supply, pipeline expansions on the Northern Border and TransCanada pipelines provided Canadian gas full access to higher priced U.S. markets. Consequently, the difference between U.S. and Canadian prices narrowed sharply. Thus, while warm temperatures caused U.S. gas prices to fall by 25 percent last winter, Alberta spot prices actually increased by 52 percent over the same time frame.

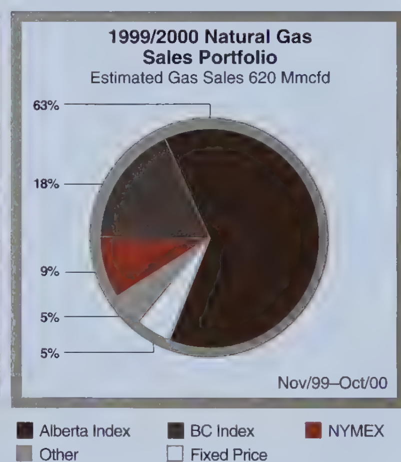
In 1999, 75 percent of Anderson Exploration's natural gas was sold directly by the Company. Contract terms varied from day to day sales to volume commitments of up to 15 years. The balance of the Company's sales were sold to aggregators such as ProGas, TransCanada, CanWest and Pan-Alberta. Anderson's exposure to aggregators has declined from 76 percent of sales in 1993 to an anticipated 20 percent of sales in fiscal 2000. The Company intends to continue this trend.

With sufficient pipeline export capacity, natural gas sales priced in western Canada provide superior netbacks. Anderson Exploration has structured its marketing portfolio to take full advantage of this situation. More than 80 percent of fiscal 2000 sales are currently priced in western Canada where premium prices should prevail. The Company will continue to review the appropriateness of its portfolio based on evolving market conditions.



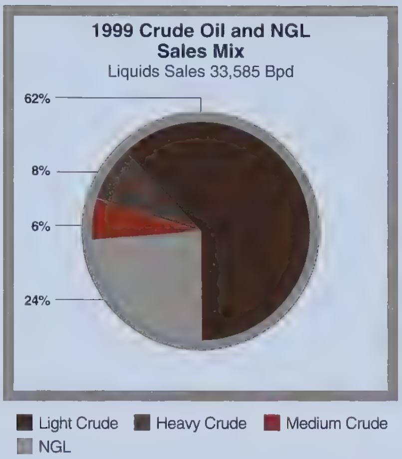
* Includes wellhead and plant gate prices.





Crude Oil and NGL

Virtually all of the Company's oil sales are tied to the West Texas Intermediate (WTI) price for crude oil. The WTI price was exceptionally volatile in 1999, dipping to a low of $US11.31 per barrel in December 1998 and then more than doubling to $US23.79 per barrel by September 1999. For our fiscal year, the WTI price averaged $US16.34 per barrel, up one percent from last year. In 1999, Anderson Exploration's average realized price for crude oil was $21.17 per barrel, up 14 percent from 1998. A weaker Canadian dollar and narrower differentials for light sour, medium and heavy crudes substantially improved the Company's netbacks despite a relatively flat year over year WTI price. With some OPEC countries and other major producing countries maintaining strict production discipline, we expect strong WTI prices during fiscal 2000.



Twenty-four percent of Anderson Exploration's total liquids sales are natural gas liquids. NGL are sold as a mix or as the individual components of ethane, propane, butane and condensate. This year, NGL prices lagged crude prices with the Company's realized NGL price averaging $15.82 per barrel, a decline of five percent. In particular, condensate, which makes up approximately 45 percent of the Company's NGL, suffered in year over year comparisons. It sold at a significant premium to light sweet crude in 1998, but that premium disappeared in 1999.

1999 NGL STREAM

	Sales Volumes (Bpd)	% of Stream	Price per Bbl
Ethane	684	9%	$ 8.37
Propane	2,044	25%	$11.33
Butane	1,674	21%	$12.19
Condensate	3,618	45%	$21.45
Total	8,020	100%	$15.82

Straddle Plants

Anderson Exploration owns an average 10.4 percent interest in two straddle plants located at Empress, Alberta. These plants are located on main gas transmission lines at the Alberta border and extract NGL, primarily ethane, propane and butane. The Company processes its own gas and a small amount of third party gas. Anderson Exploration's share of the NGL from this facility was 2,133 barrels per day in 1999 compared to 1,808 barrels per day last year. These volumes are not included in the Company's NGL sales figures. Volumes increased year over year reflecting plant modifications at both plants, including the addition of ethane recovery. Anderson Exploration profits from the difference between the energy value of NGL sold as liquid and the value of maintaining the energy content in gaseous form and selling it as natural gas. Depressed NGL prices and higher natural gas prices produced modest returns on these assets in 1999.

PIPELINE OPERATIONS

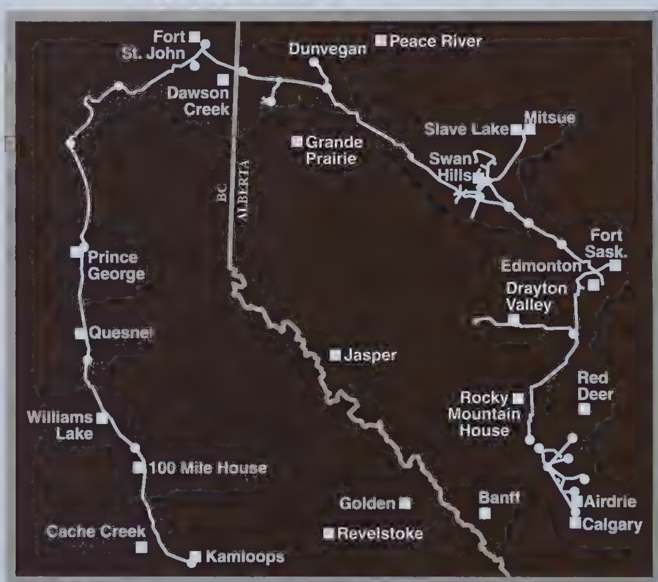
Anderson Exploration operates and is a 50 percent owner of Federated Pipe Lines Ltd. Federated's extensive pipeline system transports crude oil and NGL in Alberta and British Columbia. Federated has about 2,000 miles of pipelines with the capacity to move about 220,000 barrels of crude oil and 190,000 barrels of NGL per day. Throughput volumes in fiscal 1999 averaged 232,800 barrels per day compared to 231,000 barrels per day last year. Pipeline operations provided the Company with $8 million in cash flow from operations and $4 million in earnings in 1999.

Throughput volumes on the pipeline system were less than anticipated in fiscal 1999. This was the result of the loss of NGL deliveries from Taylor, British Columbia due to an explosion at a third party liquids extraction plant. In addition, there was an overall reduction in crude oil deliveries as a result of sharply lower drilling

activity caused by the low crude oil price environment that persisted throughout the first half of fiscal 1999. The Taylor extraction plant shut down occurred on January 27, 1999. It is anticipated that extraction plant deliveries will resume full operation in January 2000. This should result in an incremental 15,000 barrels of NGL deliveries per day onto the Federated Northern pipeline. The Federated Northern pipeline system has receipt points at Taylor, British Columbia and at Valhalla, Doe Creek and Dunvegan in Alberta. The pipeline is a batch operated system capable of delivering natural gas liquids, segregated condensate and crude oil to markets in the Edmonton area.

Despite the setbacks in fiscal 1999, Federated has a well positioned pipeline infrastructure capable of providing crude oil and NGL transportation service out of many of the growth areas in the west half of Alberta and in northeast British Columbia. These service areas are seeing renewed growth due to the current strong crude oil and natural gas prices.

FEDERATED PIPELINE SYSTEM



HEALTH, SAFETY AND ENVIRONMENT

Anderson Exploration is committed to protecting the health and safety of our employees and the public, as well as preserving the quality of the environment. Anderson Exploration has declared its support for the Environment, Health and Stewardship Program initiated by the Canadian Association of Petroleum Producers. This program is a commitment to industry and individual company excellence in health, safety and environmental performance and will facilitate communication to all stakeholders.

Health and Safety

An ongoing priority for Anderson Exploration is the protection of the public by ensuring effective emergency response plans are prepared and implemented. As part of the Company's Y2K preparations, the corporate and field district response plans were updated to ensure that public safety issues were identified. The revised plans are expected to meet the new standards being proposed by the Alberta Energy and Utilities Board.

In 1999, Anderson Exploration experienced 12 reportable injuries, all minor in nature. There was a 50 percent reduction in the Company's motor vehicle accident rate. A comprehensive health and safety audit of Anderson Exploration's operations was completed by an external auditor confirming our belief that health and safety requirements are being effectively managed by the Company.

Environment

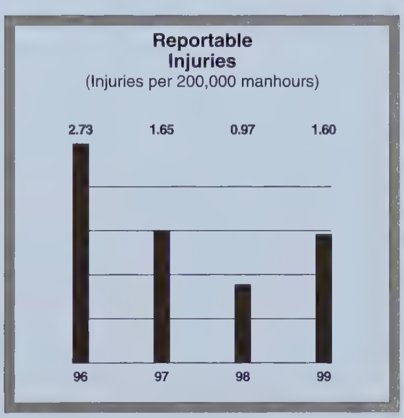
Anderson Exploration's goal is to reduce emissions by improving the efficiency of our operations. The Company is active in research and development projects related to emissions management. Recently, the Company has taken steps to reduce benzene emissions from glycol dehydrators. Currently, 98 percent of Company operated dehydrators are in compliance with voluntary emissions targets. A plan is also being developed to ensure that new gas flaring requirements are effectively managed. The number of reportable spills and the total volume spilled was similar to last year, and significant progress was made toward implementing comprehensive inspection and upgrade programs targeted at improving the integrity of our pipelines and storage tanks.

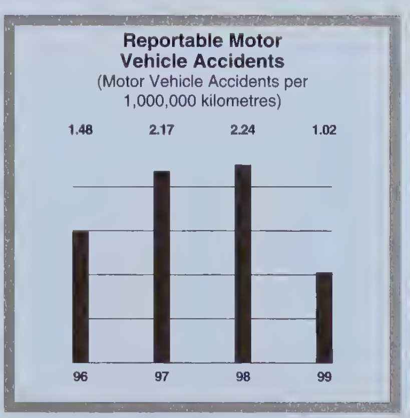
During 1999, Anderson Exploration spent $6 million on well abandonment and site restoration activities. In total, 58 wells were abandoned and reclamation certificates were received for 31 sites. Anderson Exploration continued to assess and remediate sites impacted by historic operations, with the most active programs at Turner Valley, Swan Hills, Carstairs and Fort St. John.

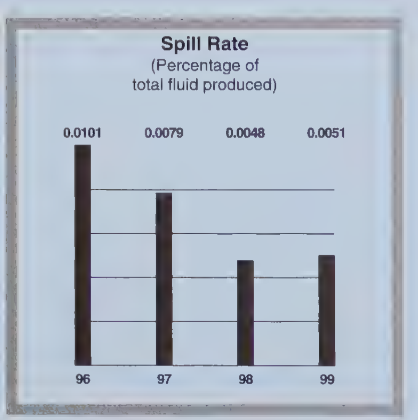
The Company has taken a leadership role in advancing the use of risk based techniques for setting and achieving site clean up objectives. Independent research at our Turner Valley Soil Treatment Area and at Olds College, participation in industry research initiatives through the Petroleum Technology Alliance of Canada and ongoing discussion with both provincial and federal regulators are a few of the activities undertaken in this area.

Regulatory Compliance and Community Relations

During 1999, the Alberta Energy and Utilities Board advised industry of an "enforcement ladder" strategy for improving regulatory compliance. This strategy establishes a step-by-step process for applying appropriate enforcement actions for non-compliance. Companies with a history of non-compliance will be subject to escalating consequences that are clearly identified by the ladder. Anderson Exploration has developed a plan for managing our corporate compliance. The Company also works with landowners to ensure that concerns such as noise and odour complaints are resolved in a mutually agreeable manner. We have initiated a review of both our regulatory and public communications practices to ensure we maintain the positive relationships with regulators and landowners that we now enjoy.







ANALYSIS

Cash flow from operations increased 29 percent over last year to a record level of $396 million or $3.19 per share. Earnings increased 186 percent to $70 million or $0.57 per share. The results demonstrate the impact that our leverage to natural gas and the improving prices for that commodity have on our financial results.

Management's Discussion and Analysis

DAVID SCOBIE
Senior Vice President & Chief Financial Officer

DARLENE WONG
Manager of Financ

The following discussion and analysis of financial results should be read in conjunction with the consolidated financial statements for the year ended September 30, 1999 and is based on information available at November 16, 1999. Information provided herein for fiscal 2000 is based on assumptions regarding future events and is subject to risks and uncertainties that may cause actual results to vary materially from these estimates. Where amounts are expressed on a barrel of oil equivalent basis, gas volumes have been converted to barrels of oil at six thousand cubic feet per barrel. This conversion ratio approximates the relative energy content between gas and oil.

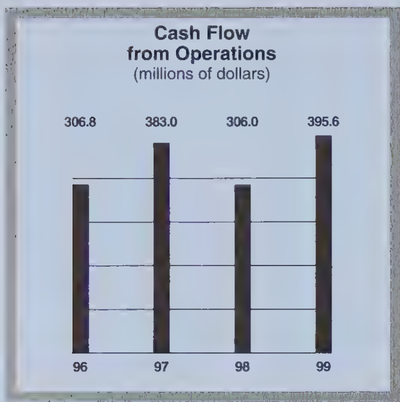
RESULTS OF OPERATIONS

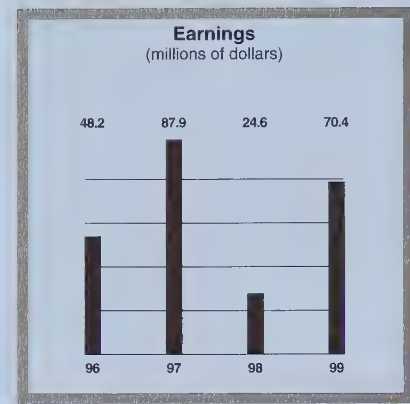
Overview

Higher prices together with increased gas sales volumes and reduced operating costs were the primary factors contributing to the Company's excellent financial results in fiscal 1999. Cash flow from operations increased 29 percent over last year and earnings increased 186 percent. Low oil prices resulted in cuts to the capital expenditure program midway through the year. Lower capital spending and increased cash flow from operations allowed the Company to retire a substantial portion of its debt in the year. The Company exited fiscal 1999 with a long term debt to cash flow ratio of 1.4, a 39 percent improvement from last year's ratio of 2.3.

CASH FLOW FROM OPERATIONS AND EARNINGS

(millions of dollars, except per share amounts)	1999	1998	% Change
Cash flow from operations			
Oil and gas	$ **387.6**	$ 296.3	31
Pipeline	**8.0**	9.7	(18)
Cash flow from operations	$ **395.6**	$ 306.0	29
Cash flow from operations per share (basic)	$ **3.19**	$ 2.49	28
Earnings			
Oil and gas	$ **66.4**	$ 17.9	271
Pipeline	**4.0**	6.7	(40)
Earnings	$ **70.4**	$ 24.6	186
Earnings per share (basic)	$ **0.57**	$ 0.20	185





Oil and Gas Operations

Oil and Gas Revenues Oil and gas revenues in fiscal 1999 have increased substantially over 1998, primarily as a result of higher prices received for natural gas and crude oil. On a barrel equivalent basis, prices increased 20 percent over last year. However, oil development projects were deferred and uneconomic heavy oil volumes continued to be shut in for the first half of the year before oil prices began their recovery. This led to lower oil sales in the year, adversely affecting oil and gas revenue. The following table shows the components of revenue and the effect of changes in prices and sales volumes. In fiscal 1999, natural gas sales made up 74 percent of total sales volumes and 67 percent of total oil and gas revenue.

OIL AND GAS REVENUES

(millions of dollars)	Gas	Oil	NGL	Other*	Total
Fiscal 1998 revenue	$ 392.6	$ 201.6	$ 44.7	$ 7.7	$ 646.6
Increase (decrease) in prices	108.9	28.7	(2.1)	–	135.5
Increase (decrease) in sales volumes	12.0	(32.8)	3.7	–	(17.1)
Other	–	–	–	4.5	4.5
Fiscal 1999 revenue	**$ 513.5**	**$ 197.5**	**$ 46.3**	**$ 12.2**	**$ 769.5**
Percentage of total revenue – 1998	61%	31%	7%	1%	100%
Percentage of total revenue – 1999	**67%**	**26%**	**6%**	**1%**	**100%**
Percentage of total sales volumes – 1998	71%	23%	6%		100%
Percentage of total sales volumes – 1999	**74%**	**20%**	**6%**		**100%**
Fiscal 1998 average price	$ 1.94/Mcf	$ 18.53/Bbl	$ 16.61/Bbl		$ 13.67/Boe
Fiscal 1999 average price	**$ 2.48/Mcf**	**$ 21.17/Bbl**	**$ 15.82/Bbl**		**$ 16.44/Boe**

* Consists of amortization of natural gas contract settlement payments, straddle plant net revenues, gains on brokered gas sales and, in fiscal 1998, foreign exchange hedging gains.

Natural gas sales volumes increased to 568 million cubic feet per day in fiscal 1999. Exploration and development programs resulted in new gas production in the Foothills, northeast British Columbia, northeast Alberta and the Peace River Arch areas. The Company's efforts were directed towards gas plays in anticipation of higher demand and increased prices. This new production replaced declines in other fields. Natural gas sales volumes were close to the 570 million cubic feet per day that was forecast at the beginning of the year. The slight shortfall was due to two Nova pipeline outages in the Peace River Arch area that reduced sales by an average of eight million cubic feet per day for the year. In fiscal 2000, gas sales are expected to increase to 620 million cubic feet of gas per day.

Natural gas prices were strong throughout fiscal 1999 despite warmer than normal winter temperatures. As anticipated, Canadian natural gas prices improved dramatically as incremental export pipeline capacity provided increased access to U.S. markets. The Company was well positioned to take advantage of these increases with a significant portion of its portfolio linked to premium pricing in Alberta and British Columbia. In fiscal 1999, the Company sold approximately 75 percent of its natural gas directly to end users and marketing intermediaries under contracts of varying terms. The remaining 25 percent was sold to supply aggregators, who in turn sold the gas to purchasers along gas pipeline routes, generally at market sensitive prices. In fiscal 2000, it is anticipated that an even smaller portion of our portfolio will be sold to supply aggregators and that over 80 percent of our natural gas sales portfolio will be priced in western Canada.

NGL sales volumes increased to 8,020 barrels per day in the 1999 fiscal year. High NGL yields at the Highway gas plant in British Columbia and the start up of ethane extraction at Dunvegan were the major contributors to the increase. NGL prices tend to follow oil prices and were also depressed for much of the year. Although there was a recovery toward the end of the year, NGL prices still lagged behind last year as the premium condensate prices experienced in 1998 moderated in 1999. The Company sells its NGL both as NGL mix and as the individual components of ethane, propane, butane and condensate in Alberta and Ontario markets. Sales prices are indexed to major NGL market centres, such as Edmonton, Alberta, Sarnia, Ontario and Belvieu, Texas. NGL sales volumes are not expected to change significantly in fiscal 2000.

NATURAL GAS AND NGL NETBACKS

(per Mcf*)	1999	1998	% Change
Sales revenue	**$ 2.49**	$ 2.00	25
Royalties	**(0.43)**	(0.35)	23
Operating costs	**(0.43)**	(0.37)	16
Netback	**$ 1.63**	$ 1.28	27
Royalty percentage	**17%**	18%	(6)
Daily sales volumes – natural gas (Mmcfd)	**568**	555	2
Daily sales volumes – NGL (Bpd)	**8,020**	7,376	9

* NGL converted to natural gas at 1 Bbl = 6 Mcf.

Oil sales volumes decreased to 25,565 barrels per day in fiscal 1999, primarily as a result of a reduction in capital spending on oil projects. In addition, heavy oil sales volumes were down as wells with high operating costs were shut in. The effect of low oil prices experienced in early fiscal 1999 and the resultant reduction in spending on oil projects will continue to be felt in fiscal 2000. Conventional sales volumes are expected to remain relatively unchanged. However, additional heavy oil volumes are expected to be brought on stream, increasing overall oil sales to about 26,300 barrels per day.

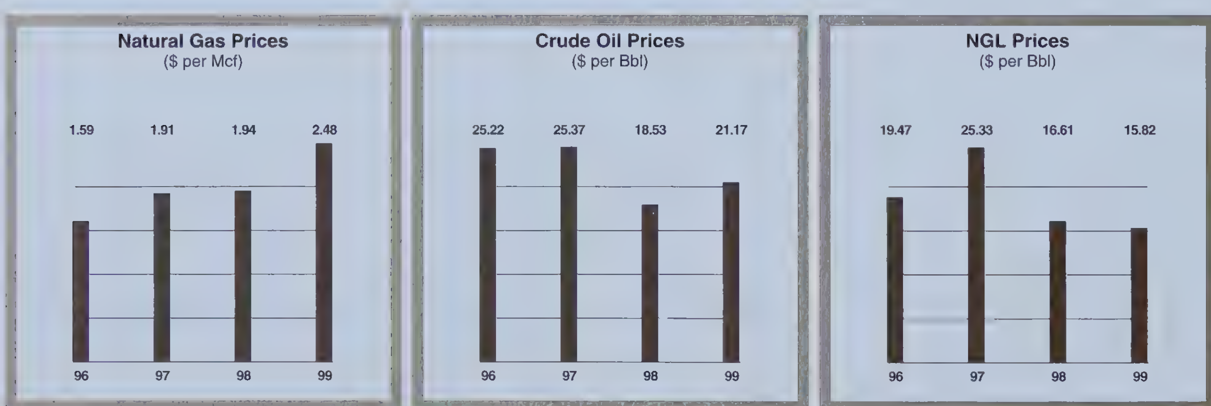
The oil and gas industry was faced with extremely low oil prices through the winter of 1999. In early spring, OPEC members met and agreed on production cuts to support the oil price. There has been a high degree of compliance among OPEC members, which has resulted in a dramatic turnaround in prices over the latter part of the Company's fiscal year. The price received for conventional oil increased slightly over last year to average $21.94 per barrel in fiscal 1999. The average price received by the Company in the fourth quarter of fiscal 1999 was $29.51 per barrel, up significantly from the $17.48 per barrel received in first quarter. Price differentials between light and heavy crude narrowed considerably as fiscal 1999 progressed. The Company sold 2,725 barrels per day of heavy oil in fiscal 1999, down 22 percent from last year. The average price received for heavy oil was $14.68, up 65 percent from last year.

CRUDE OIL NETBACKS

(per Bbl)	1999	1998	% Change
Sales revenue	**$ 21.17**	$ 18.53	14
Hedging gains	–	0.04	(100)
Royalties	**(3.16)**	(2.92)	8
Operating costs	**(5.97)**	(7.26)	(18)
Netback	**$ 12.04**	$ 8.39	44
Royalty percentage	**15%**	16%	(6)
Daily sales volumes (Bpd)	**25,565**	29,808	(14)

Other oil and gas revenue in fiscal 1999 consisted primarily of the amortization of settlement payments received on the termination of certain long term natural gas sales contracts. The amortization increased by $5.3 million from last year as a result of payments received in June 1998. This increase was offset somewhat by lower straddle plant revenues, as feedstock gas prices continued to rise and NGL prices were low.

AVERAGE COMPANY PRICES



Royalties Oil and gas royalties, net of the Alberta Royalty Tax Credit (ARTC), increased to $125.9 million in fiscal 1999 from $107.7 million in the previous year. The increase is due to higher revenues. However, royalties as a percentage of revenue decreased slightly from 17 percent last year to 16 percent this year. Higher prices did not increase royalty rates as the Company's corporate average gas price in Alberta exceeded the Alberta Reference Price on which Alberta gas Crown royalties are calculated. In addition, the Company recorded favorable gas cost allowance adjustments during the year. Royalty rates are expected to increase in fiscal 2000 as product prices continue to rise.

Operating Expenses Oil and gas operating expenses decreased to $153.6 million in fiscal 1999 compared to $160.5 million in the previous year. Anderson Exploration field staff continued to pursue a program of cost reduction, resulting in a three percent decrease in operating costs on a barrel equivalent basis. In addition, operating expenses in fiscal 1998 were impacted by high industry activity, which caused higher costs for services and equipment. This trend was reversed in fiscal 1999. Expenses for heavy oil properties have decreased markedly, as wells with high operating costs were shut in during 1998 and the cost of condensate, used as diluent for transporting heavy oil, was much lower. Operating expenses are expected to increase next year, as costs for new production from more remote areas will exceed the costs achieved historically.

Other Revenue Other revenue was $1.3 million in fiscal 1999 compared to $9.4 million in the previous year. The primary source of other revenue in fiscal 1999 was the receipt of dividends from an investment in a natural gas aggregator. In fiscal 1998, the Company recorded a gain on the sale of an interest in an oil sands lease.

General and Administrative Expenses General and administrative expenses were $40.7 million in fiscal 1999 compared to $31.6 million in the previous year. General and administrative expenses have increased 30 percent from last year on a barrel equivalent basis. The Company had a higher staff count in fiscal 1999, resulting in higher salaries and benefits. Due to the low oil price early in the year, a temporary salary freeze was implemented. This freeze was lifted at the beginning of the Company's fourth quarter. With the reduced activity undertaken during 1999, overhead recoveries decreased substantially, particularly those relating to capital expenditures.

OIL AND GAS GENERAL AND ADMINISTRATIVE EXPENSES

(millions of dollars)	1999	1998	% Change
Gross expense	$ **54.6**	$ 50.5	8
Operator recoveries	**(13.9)**	(18.9)	(26)
Net expense	$ **40.7**	$ 31.6	29
Average cost per Boe			
Gross expense	$ **1.17**	$ 1.07	9
Operator recoveries	**(0.30)**	(0.40)	(25)
Net expense	$ **0.87**	$ 0.67	30

General and administrative expenses are expected to increase in fiscal 2000 as a result of salary increases granted in July 1999. An increase in staff is also expected in light of the anticipated increase in field activities.

The Company does not capitalize any general and administrative expenses or allocate any administrative costs to operating expenses, except to the extent of the Company's working interest in operated capital expenditure programs and operated producing properties where overhead fees are charged to third parties. The Company does not charge overhead fees on 100 percent owned projects. In addition, the Company does not capitalize the salaries and other expenses of its exploration department as direct capital expenditures. These policies allow the readers of the consolidated financial statements to assess the Company's true administrative expenditures.

Interest Expense Interest expense related to oil and gas operations decreased slightly to $42.5 million in 1999 from $44.0 million in 1998. The Company reduced its long term debt balance significantly in the current year as a result of more cash available from operations and from a reduced capital program. However, the effect of lower average debt levels was offset by higher interest rates and fees in fiscal 1999. The Company did not capitalize any interest related to its oil and gas operations in 1999 or 1998. While the ending debt level is expected to be similar, the average debt outstanding throughout the year will decline in fiscal 2000 and this is expected to result in slightly lower interest costs for oil and gas operations next year.

Current Taxes Current taxes related to oil and gas operations increased to $20.5 million in fiscal 1999 from $6.7 million in the previous year. Current income taxes related to oil and gas operations amounted to $13.6 million. Income has increased in the current year without a corresponding increase in available deductions for exploration and development activities due to the cutback in capital spending. Current taxes also include the federal large corporations tax, provincial capital taxes and provincial resource surcharges. In fiscal 1998, these balances comprised the total current tax provision, as no income tax was payable on oil and gas operations.

The Company has approximately $766 million in unused tax pools related to its oil and gas operations. A portion of these tax pools are successored, as pools acquired in corporate acquisitions are generally dedicated to sheltering the income from properties held by an acquired company at the time of acquisition.

OIL AND GAS TAX POOLS

At September 30, 1999 (millions of dollars)

Canadian Development Expenditures	$	142
Canadian Oil and Gas Property Expenditures		304
Undepreciated Capital Cost		282
Other		38
	$	766

It is anticipated that current taxes will decrease in fiscal 2000. The decrease will occur primarily as a result of higher capital expenditures being incurred.

Cash Flow From Operations Cash flow from oil and gas operations was $387.6 million in 1999 compared to $296.3 million in 1998. On a barrel equivalent basis, cash flow from operations increased 32 percent to $8.28 per barrel of oil equivalent in fiscal 1999. The Company's cash flow is discretionary and available for capital programs and reduction of long term obligations.

CASH FLOW AND EARNINGS FROM OIL AND GAS OPERATIONS

($ per barrel equivalent)	1999	1998	% Change
Oil and gas revenues	$ **16.44**	$ 13.67	20
Royalties	**(2.69)**	(2.28)	18
Operating costs	**(3.28)**	(3.39)	(3)
	10.47	8.00	31
Other revenues	**0.03**	0.01	200
General and administrative	**(0.87)**	(0.67)	30
Interest	**(0.91)**	(0.93)	(2)
Current taxes	**(0.44)**	(0.14)	214
Cash flow from operations	**8.28**	6.27	32
Depletion and depreciation	**(5.57)**	(5.35)	4
Future site restoration provision	**(0.39)**	(0.25)	56
Deferred taxes	**(0.90)**	(0.49)	84
Gain on sale of property, plant and equipment	–	0.19	(100)
Earnings	$ **1.42**	$ 0.37	284

Depletion and Depreciation Depletion and depreciation provided on the unit of production method is based on total proven reserves with conversion of natural gas to oil using their relative energy content. The provision for depletion and depreciation on oil and gas properties increased to $260.7 million in 1999 from $252.8 million in 1998. As a result of an increase in finding and development costs in fiscal 1998, the Company's rate for providing depletion and depreciation of oil and gas assets increased to $5.57 per barrel of oil equivalent from $5.35 last year. The rate is expected to decrease slightly in fiscal 2000 as a result of the lower finding and development costs achieved in the current year, while the total depletion and depreciation expense will increase as a result of higher sales volumes.

Future Site Restoration The Company provided $18.5 million for future site restoration related to oil and gas operations in 1999 compared to $11.7 million in 1998. At September 30, 1998, the estimate of future costs for site reclamation and well abandonments was increased significantly to reflect the anticipated higher costs associated with stricter environmental regulatory requirements and actual costs experienced for well abandonments. As a result, the current year provision increased to $0.39 per barrel of oil equivalent from $0.25 in the previous year. This rate is not expected to change significantly in fiscal 2000.

Deferred Taxes Deferred tax expense on oil and gas operations increased to $42.2 million in fiscal 1999 from $23.0 million last year due to higher pre-tax earnings. The total tax provision as a percentage of pre-tax earnings was 48.5 percent compared to 62.3 percent last year. In fiscal 1999, Crown royalties and production taxes paid were approximately the same as resource allowance claimed. In fiscal 1998, resource allowance was lower than the non-deductible Crown payments, resulting in a higher effective tax rate. In addition, large corporations tax and provincial capital taxes and resource surcharges have a larger effect on the tax rate at lower levels of earnings.

Earnings Earnings from oil and gas operations were $66.4 million in 1999 compared to $17.9 million in 1998. On a barrel equivalent basis, earnings increased 284 percent from last year, primarily as a result of higher product prices in the year.

Pipeline Operations

The Company's pipeline transportation activities are conducted through its 50 percent interest in Federated Pipe Lines Ltd. The Company accounts for its interest in Federated using the proportionate consolidation method, whereby the Company's proportionate share of the assets, liabilities, revenues and expenses are included in its consolidated financial statements.

Cash flow from pipeline operations was $8.0 million in 1999 compared to $9.7 million in 1998. Earnings were $4.0 million in 1999 compared to $6.7 million last year. Daily average pipeline gatherings were up slightly in 1999 compared to 1998. Revenues resulting from the addition of the Northern line and tariff increases on the crude oil and Cremona lines were largely offset by lower volumes on other lines operated by Federated. In addition, a fire and explosion at the Solex Younger Extraction plant in Taylor, British Columbia in December 1998 had a significant impact on the Northern line, as Solex was a key shipper. The Solex plant is expected to start up again in 2000 and pipeline earnings and cash flow from operations are expected to increase next year.

Accounting Changes

The Company has not adopted the new CICA accounting recommendations for Accounting for Income Taxes or for Employee Future Benefits. The new recommendations for Accounting for Income Taxes moves to the liability method of tax allocation accounting. The new accounting recommendations for Employee Future Benefits modifies the requirements for pension costs and obligations and applies these requirements to non-pension benefits. The Company is not required to adopt the new recommendations until October 1, 2000. Adoption of the new standards would not have had a material effect on the cash flow from operations or earnings of the Company in fiscal 1999.

CAPITAL EXPENDITURES

Net capital expenditures were $289.2 million in fiscal 1999 compared to $527.7 million in 1998. The Company replaced 115 percent of its annual production with proven reserves, after revisions. The Company expected to spend $345.0 million in 1999, but spending was cut back early in the year when virtually all oil projects were deferred. As oil prices recovered, oil projects were reinstated. However, drilling activity was severely constrained by a long spring breakup period and very wet weather experienced well into the summer months, severely limiting the Company's access to its areas of interest. The 1999 capital program was funded by cash flow from operations.

In September 1999, in partnership with Petro-Canada, the Company was awarded Exploration Licences for two land parcels on the Mackenzie Delta in the Northwest Territories. The Company's share in each licence is 40 percent. The bid process required a commitment for a specific work program to be undertaken, and the Company was required to put up a deposit in the amount of $10.5 million, by way of a letter of credit,

for work to be completed in the next five years. This amount represents 25 percent of the Company's share of the entire work program. It is expected that exploration activity in the area will commence in fiscal 2000. In addition, in November 1999, the Company acquired 100 percent interests in two permits in the Eagle Plains area of the Yukon Territory for a total work commitment of $20.4 million over six years.

NET CAPITAL EXPENDITURES

(millions of dollars)	1999	1998	% Change
Exploration drilling and completion	**$ 66.8**	$ 80.0	(17)
Seismic	**26.0**	15.4	69
Land acquisition and retention	**38.3**	30.1	27
Total exploration expenditures	**131.1**	125.5	4
Development drilling, completion and recompletion	**53.9**	131.8	(59)
Plant and production facilities	**75.0**	108.9	(31)
Miscible fluids	**3.3**	5.7	(42)
Total development expenditures	**132.2**	246.4	(46)
Property acquisitions*	**23.1**	123.4	(81)
Straddle plants	**4.5**	2.4	88
Pipeline	**5.3**	51.5	(90)
Corporate	**2.6**	2.7	(4)
Gross capital expenditures	**298.8**	551.9	(46)
Proceeds on disposition of properties	**(9.6)**	(24.2)	(60)
Net capital expenditures	**$ 289.2**	$ 527.7	(45)

* 1998 property acquisitions include $98.8 million for the acquisition of an additional 10.6 percent interest in Swan Hills Unit No. 1.

Net capital expenditures are expected to increase to $565 million in fiscal 2000. The Company anticipates spending $250 million on exploration and land purchases and $255 million on development projects and expects to drill over 500 gross wells. The Company will supplement its activities in the traditional areas of the Peace River Arch and northeast Alberta with significant expenditures in northeast British Columbia, central Alberta and the Foothills. These latter three areas will account for nearly 75 percent of exploration expenditures in fiscal 2000. Approximately 95 percent of the exploration budget and 65 percent of the development budget will be directed toward gas plays. Activity on oil projects will focus on heavy oil projects and other projects that were deferred in fiscal 1999.

Finding and development costs have decreased from last year as a result of some significant gas discoveries as well as a more competitive service cost environment due to less industry activity. New technology is also reducing the costs of drilling some gas and heavy oil wells in the Plains region. Finding and development costs are expected to increase modestly in fiscal 2000 as industry activity picks up again and as additional capital is spent to develop proven undeveloped reserves.

FINDING AND DEVELOPMENT COSTS

(Boe calculated at 6:1)		1999		1998
Net capital expenditures ($ millions)	$	**289.2**	$	527.7
Less pipeline and straddle plant expenditures ($ millions)		**(9.8)**		(53.9)
		279.4		473.8
Site restoration expenditures ($ millions)		**6.3**		6.3
	$	**285.7**	$	480.1
Reserve additions before revisions (million Boe)				
Proven		**58.4**		70.6
Proven plus one half probable		**72.2**		83.7
Reserve additions after revisions (million Boe)				
Proven		**53.9**		62.7
Proven plus one half probable		**50.5**		64.5
Finding and development costs before revisions – current year				
Proven	$	**4.89**	$	6.80
Proven plus one half probable	$	**3.96**	$	5.74
Finding and development costs after revisions – current year				
Proven	$	**5.31**	$	7.66
Proven plus one half probable	$	**5.66**	$	7.44
Finding and development costs after revisions – three year average				
Proven	$	**6.50**	$	6.47
Proven plus one half probable	$	**6.22**	$	6.18

FINANCIAL RESOURCES AND LIQUIDITY

The Company's financial obligations decreased by $132.2 million in fiscal 1999. Long term debt decreased from $695.5 million at September 30, 1998 to $545.2 million at September 30, 1999 while the net working capital deficiency increased from $11.9 million to $30.0 million. Increased cash flow from operations and reduced capital spending provided most of the funds for the debt repayments. Net capital expenditures of $289.2 million and site restoration expenditures of $6.3 million represented 75 percent of cash flow from operations. Proceeds of $42.7 million were received on the issue of common shares under the employee stock option plan and stock savings plan. At September 30, 1999, the Company had unused long term and operating lines of credit of $281.4 million. A sinking fund payment of $0.9 million is the only long term debt repayment required to be made in fiscal 2000 and this amount has been included in the working capital deficiency noted above.

The Company uses interest rate swaps to effectively fix the interest rate on a significant portion of outstanding debt. The swaps are described in the notes to the consolidated financial statements.

Cash flow from operations covered interest expense 10.0 times in 1999 compared to 7.9 times in 1998. At year end, long term debt was 1.4 times 1999 cash flow from operations compared to 2.3 times in 1998. In fiscal 2000, the ratio of long term debt to cash flow from operations is expected to decrease slightly.

In order to maximize its financing options in the future, including the refinancing of the oil indexed debentures on October 31, 2000, the Company applied for and received bond ratings of A (low) and BBB (high) for senior unsecured debentures from two bond rating agencies.

SHARE INFORMATION

The Company's common shares were listed for trading on The Toronto Stock Exchange in 1988. At September 30, 1999, there were 126,030,334 common shares outstanding. During 1999, 2,769,982 common shares were issued for proceeds of $42.7 million under the employee stock option and stock savings plans. The Company's market capitalization at September 30, 1999 was $2.4 billion. Trading in the common shares is very liquid with a 108 percent turnover ratio in fiscal 1999.

SHARE PRICE

	1995 Year	1996 Year	1997 Year	1998 Year	1999 Q1	1999 Q2	1999 Q3	1999 Q4	1999 Year
High	16.25	15.25	20.25	19.40	**17.30**	**15.20**	**19.70**	**22.60**	**22.60**
Low	10.75	11.62	13.70	12.50	**12.60**	**11.60**	**14.15**	**18.05**	**11.60**
Close	12.63	13.70	17.20	16.00	**13.90**	**14.45**	**19.35**	**19.40**	**19.40**
Volume (000)	87,095	87,963	107,697	100,295	**23,614**	**26,587**	**38,070**	**46,309**	**134,580**

On November 26, 1999, Anderson Exploration filed a Notice of Intention to make a Normal Course Issuer Bid with The Toronto Stock Exchange. The Company believes that the underlying value of its common shares is not reflected in recent market prices and, accordingly, believes that the share purchase program provides value by reducing the number of shares outstanding. Recent increases in commodity prices have led to substantial increases in cash flow from operations and a corresponding reduction in long term debt. Indications are that this situation will continue in the coming fiscal year, which will provide funding for the issuer bid. At such time as common shares become available at prices which make purchase of them an appropriate use of the Company's funds, the Company will make normal course purchases through the facilities of The Toronto Stock Exchange. Anderson Exploration may acquire up to five percent of its outstanding common shares but is not required to purchase any.

BUSINESS RISKS

Natural gas and crude oil exploration, production and marketing operations involve a number of business risks. These include the uncertainty of finding new reserves, the instability of commodity prices, operational risks and volatility of capital markets. These risks are managed by employing competent professional staff, employing sound operating practices and utilizing cash flow from operations and the prudent issue of equity to fund a significant portion of capital expenditures so that debt does not become a burden.

The Company generates its exploration prospects internally. Extensive geological, geophysical, engineering and environmental analyses are performed before committing to the drilling of new prospects. These analyses are used to ensure a suitable balance between risk and reward.

Commodity prices are influenced by supply and demand, both locally and worldwide, competition, the U.S. dollar exchange rate, transportation, political stability and seasonal changes in demand resulting from weather patterns in the Company's marketing areas. The value of the Canadian dollar, which is influenced by economic and political factors, affects all of the Company's crude oil sales and most of its natural gas sales. To reduce the impact of these factors, the Company maintains a balanced portfolio of sales contracts. The Company does enter into physical contracts for the sale of natural gas at fixed prices and terms; however, other forms of hedging contracts are subject to approval by the Board of Directors. Anderson Exploration's current policy is that it will not hedge natural gas or crude oil prices.

The Company has fixed the rate of interest on approximately 85 percent of its long term debt obligations. Between 1996 and 1998, the Company fixed the rate of interest on $253.0 million of its outstanding bank loans through swap agreements at an average rate of 6.69 percent. The agreements mature at various dates between 2001 and 2007. The Company has fixed the rate of interest on its $200.0 million oil indexed debentures at 8.26 percent to their maturity on October 31, 2000, also through the use of swap agreements. In addition, the Company, through its 50 percent ownership of Federated, has $10.8 million of sinking fund debentures outstanding which bear interest at a fixed rate of 9.54 percent and mature in October 2002.

Historically, regulatory issues and taxation have had a significant impact on the oil and natural gas industry. With the deregulation of the industry beginning in 1985 and stable taxation levels, there is currently a reasonable operating environment in Canada for financially healthy companies. While the Company is not aware of anything imminent, the potential exists for this environment to change due to changes in taxation and energy policy.

The industry is subject to extensive regulations imposed by governments related to the protection of the environment. Environmental legislation in western Canada has undergone major revisions. Environmental standards and compliance are more stringent. The Company is committed to meeting its responsibilities to protect the environment wherever it operates and has instituted a series of controls and procedures with respect to environmental protection. The estimated liability for future abandonment and restoration costs is reviewed annually. Total future costs are estimated to be $277.7 million, of which $61.1 million has been recorded as a liability to date. The Company is committed to managing this liability and will take full advantage of new technology during the drilling, producing and abandonment phases of its operations to keep these costs as low as possible.

SENSITIVITIES

The Company's earnings and cash flow from operations are highly sensitive to changes in factors that are beyond its control. An estimate of the Company's sensitivities to changes in commodity prices, exchange rates and interest rates is summarized below.

Change of	Cash Flow From Operations		Earnings	
	$ Millions	$/Share	$ Millions	$/Share
$0.10/Mcf in the price of natural gas	$ 17.8	$ 0.14	$ 10.6	$ 0.09
$US1.00/Bbl in the WTI crude oil price	$ 13.3	$ 0.10	$ 8.3	$ 0.07
$US0.01 in the U.S./Cdn. exchange rate	$ 6.5	$ 0.05	$ 4.1	$ 0.04
1% in short term interest rates	$ 0.6	$ –	$ 0.2	$ –

YEAR 2000

In 1997, the Company began looking at its computer systems to assess the potential problems and costs associated with the year 2000. The problem revolves around the fact that many computer systems and software applications have been designed to recognize dates using only the last two digits of the year. In the year 2000, it is anticipated that some systems and programs may not function properly. We identified the major areas of vulnerability and tested the systems involved. Testing and remediation or replacement of non-compliant systems was completed in the Company's fourth quarter. A clean management program was implemented

to ensure that the acquisition of new systems and devices meet year 2000 readiness criteria. While the Company has a comprehensive plan to deal with the year 2000 issue, it is not possible to be certain that all aspects of the problem will be fully resolved, particularly with respect to the risks associated with the level of preparedness of our suppliers and other business associates. As a result, formal contingency plans have been completed that are designed to continue safe operations and protect the environment in the event that internal or third party problems occur. They include site specific contingency plans that are being updated continuously as new information becomes available from our business partners. Estimated costs of dealing with the year 2000 issue, not including the cost of salaries of employees involved in year 2000 testing, amounted to approximately $2 million over the past three years.

BUSINESS PROSPECTS

Early last year, faltering demand for crude oil exacerbated by high rates of OPEC production set the stage for the lowest crude oil prices in many years. Revenue shortfalls created distress in the oil industry, and for oil producing countries. A turnaround in price occurred when strict adherence to OPEC and some non-OPEC production cuts brought supply and demand into balance. This allowed WTI prices to escalate beyond $US24.00 per barrel. At these prices, we expect a supply response from non-OPEC countries and some slippage in observance of quotas by OPEC members. This may moderate the price rise to a certain extent but we expect the lessons of the past year will not be soon forgotten by OPEC members. As such, our outlook for oil prices in fiscal 2000 remains positive.

In the United States, the third warm winter in a row in North America hurt U.S. natural gas prices at the same time as crude oil revenues were falling. Working capital declined and access to capital dried up. Cash strapped producers who had already reduced drilling for oil reduced gas drilling as well. Fortunately, this set the stage for a price recovery. Economic growth and electrical generation continued to improve gas demand while less drilling reduced supply. The current balanced market is expected to support strong U.S. gas prices. In a reversal of fortunes, last winter's lower U.S. gas prices did not translate into lower Canadian prices. Export pipeline capacity expansions on Northern Border and TransCanada PipeLines allowed Canadian prices to catch up to U.S. prices. So while netbacks for U.S. producers declined by 10 percent last year, Alberta spot gas prices actually improved by almost 50 percent. We expect that with Alliance Pipeline adding 1.3 billion cubic feet per day of additional export capacity in 2000, the differential between U.S. and Canadian prices will remain narrow.

The Canadian industry is now in the rare and enviable position of enjoying both strong crude oil and natural gas prices. Increasing evidence of adherence to reduced OPEC quotas provides fundamental support for excellent crude oil prices. A tightening North American supply/demand balance for natural gas bodes well for both U.S. and Canadian gas prices. The gas industry may have difficulty meeting North American gas demand requirements, especially if winter temperatures return to normal. The impact on gas prices could be significant. The Company is well positioned to capitalize on strong gas prices with 75 percent of its current production made up of natural gas and more than 80 percent of its current gas sales portfolio priced in western Canada, where premium prices should prevail.

Management's Report

Management is responsible for the preparation of the consolidated financial statements and the consistent presentation of all other financial information in this annual report.

Management maintains a system of internal controls to provide reasonable assurance that assets are safeguarded and that relevant and reliable financial information is produced in a timely manner.

External auditors, appointed by the shareholders, have examined the consolidated financial statements. Their report is presented below. The Audit Committee of the Board of Directors has reviewed the consolidated financial statements with management and the external auditors. The Board of Directors has approved the consolidated financial statements on the recommendation of the Audit Committee.

J.C. Anderson
Chairman & Chief Executive Officer

David G. Scobie
Senior Vice President & Chief Financial Officer

November 16, 1999

Auditors' Report to the Shareholders

We have audited the consolidated balance sheets of Anderson Exploration Ltd. as at September 30, 1999 and 1998 and the consolidated statements of earnings, retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at September 30, 1999 and 1998 and the results of its operations and its cash flows for the years then ended in accordance with generally accepted accounting principles.

KPMG LLP

Chartered Accountants
Calgary, Canada

November 16, 1999

Consolidated Balance Sheets

SEPTEMBER 30

(Stated in thousands of dollars)

	1999	1998
Assets		
Current assets		
Accounts receivable	$ **125,000**	$ 101,381
Inventories	**11,171**	9,753
	136,171	111,134
Property, plant and equipment (note 2)	**2,470,044**	2,445,129
	$ **2,606,215**	$ 2,556,263
Liabilities and Shareholders' Equity		
Current liabilities		
Bank indebtedness	$ **14,739**	$ 20,903
Accounts payable and accrued liabilities	**136,162**	100,265
Taxes payable	**14,332**	921
Current portion of long term debt	**900**	900
	166,133	122,989
Long term debt (note 3)	**545,234**	695,517
Other credits (note 4)	**136,678**	135,023
Deferred income taxes	**622,385**	580,018
	1,470,430	1,533,547
Shareholders' equity		
Share capital (note 5)	**791,098**	748,427
Retained earnings	**344,687**	274,289
	1,135,785	1,022,716
	$ **2,606,215**	$ 2,556,263

See accompanying notes to consolidated financial statements.

On behalf of the Board:

J.C. Anderson

Director

Director

Consolidated Statements of Earnings

YEARS ENDED SEPTEMBER 30
(Stated in thousands of dollars except per share amounts)

	1999	1998
Revenues		
Oil and gas	$ 769,546	$ 646,585
Royalties, net of ARTC of $1,470 (1998 – $1,372)	(125,878)	(107,716)
Pipeline	28,619	27,547
Other	1,571	9,529
	673,858	575,945
Expenses		
Operating	165,978	170,311
Depletion and depreciation	264,596	255,438
General and administrative	41,404	32,419
Interest (including $46,164 on long term debt; 1998 – $45,380)	46,764	46,133
Future site restoration	18,657	11,884
	537,399	516,185
Earnings before taxes	136,459	59,760
Taxes (note 7)		
Current	23,694	11,709
Deferred	42,367	23,445
	66,061	35,154
Earnings	$ 70,398	$ 24,606
Earnings per common share (note 6)		
Basic	$ 0.57	$ 0.20
Fully diluted	$ 0.56	$ 0.20
Weighted average number of common shares outstanding (thousands)	124,101	122,794

Consolidated Statements of Retained Earnings

YEARS ENDED SEPTEMBER 30
(Stated in thousands of dollars)

	1999	1998
Retained earnings, beginning of year	$ 274,289	$ 249,683
Earnings	70,398	24,606
Retained earnings, end of year	$ 344,687	$ 274,289

See accompanying notes to consolidated financial statements.

Consolidated Statements of Cash Flows

YEARS ENDED SEPTEMBER 30

(Stated in thousands of dollars, except per share amounts)

	1999	1998
Cash provided by (used in):		
Operations		
Earnings	$ 70,398	$ 24,606
Add (deduct) non-cash items:		
Depletion and depreciation	264,596	255,438
Future site restoration	18,657	11,884
Deferred taxes	42,367	23,445
Gain on sale of property, plant and equipment	(354)	(9,284)
Other	(54)	(52)
Cash flow from operations	395,610	306,037
Increase (decrease) in deferred revenue	(10,601)	61,156
Change in non-cash working capital related to operations (note 8)	22,111	17,791
	407,120	384,984
Investments		
Additions to property, plant and equipment	(298,710)	(551,891)
Proceeds on disposition of property, plant and equipment	9,553	24,233
Site restoration expenditures	(6,347)	(6,299)
Change in non-cash working capital related to investments (note 8)	2,160	(21,870)
	(293,344)	(555,827)
Financing		
Increase (decrease) in long term debt	(150,283)	150,535
Issue of common shares	42,671	12,039
	(107,612)	162,574
Increase (decrease) in cash	6,164	(8,269)
Cash position, beginning of year	(20,903)	(12,634)
Cash position, end of year	$ (14,739)	$ (20,903)
Cash flow from operations per common share (note 6)		
Basic	$ 3.19	$ 2.49
Fully diluted	$ 3.03	$ 2.41

Cash position includes cash net of current bank indebtedness. Current bank indebtedness includes outstanding cheques.

See accompanying notes to consolidated financial statements.

Notes to Consolidated Financial Statements

YEARS ENDED SEPTEMBER 30, 1999 AND 1998

(Tabular amounts in thousands of dollars, unless otherwise stated)

Anderson Exploration Ltd. ("Anderson Exploration" or "the Company") is engaged in the acquisition, exploration, development, production and pipeline transportation of oil and gas resources in western Canada. The consolidated financial statements have been prepared in accordance with generally accepted accounting principles in Canada.

1. SIGNIFICANT ACCOUNTING POLICIES

(a) Consolidation

The consolidated financial statements include the accounts of Anderson Exploration, its wholly owned subsidiaries and its 50 percent interest in Federated Pipe Lines Ltd. ("Federated"), a pipeline transportation company. The Company's interest in Federated is accounted for using the proportionate consolidation method, whereby the Company's proportionate share of the assets, liabilities, revenues and expenses are included in the consolidated financial statements.

(b) Joint interest operations

A significant proportion of the Company's oil and gas exploration, development and production activities are conducted with others and accordingly the accounts reflect only the Company's proportionate interest in such activities.

(c) Inventories

Inventories are stated at the lower of cost and net realizable value. Cost is determined using the specific item or average cost method.

(d) Property, plant and equipment

The Company follows the full cost method of accounting for oil and gas properties. Under this method, all costs relative to the exploration for and development of oil and gas reserves are capitalized into cost centres on a country by country basis. Capitalized costs include lease acquisitions, geological and geophysical costs, lease rentals on non-producing properties, costs of drilling productive and non-productive wells and plant and production equipment costs. General and administrative costs are not capitalized other than to the extent of the Company's working interest in operated capital expenditure programs to which overhead fees have been charged under standard industry operating agreements. Overhead fees are not charged on 100 percent owned projects. Proceeds received from disposals of conventional oil and gas properties and equipment are credited against capitalized costs unless the disposal would alter the rate of depletion and depreciation by more than 20 percent, in which case a gain or loss on disposal is recorded.

Depletion of oil and gas properties and depreciation of plant and production equipment are provided on the unit of production method based on total proven reserves before royalties as estimated by Company engineers. Natural gas sales and reserves are converted to equivalent units of crude oil using their relative energy content. Pipelines, buildings and other equipment are depreciated over their useful lives using the declining balance and straight line methods at rates varying from three percent to 40 percent per annum.

The Company applies a ceiling test to capitalized oil and gas property costs to ensure that such costs do not exceed the estimated future net revenues from production of proven reserves, at prices and operating costs in effect at the year end, plus the cost of unevaluated properties less management's estimate of impairment. The test also provides for estimated future administrative overhead, financing costs, future site restoration costs and taxes.

(e) **Future site restoration costs**

Provisions for future site restoration costs are made over the life of the Company's oil and gas properties using the unit of production method or, in the case of pipeline transportation assets, over the estimated service life of the pipelines. Costs are based on engineering estimates considering current regulations, costs and industry standards. Actual expenditures incurred are applied against deferred future site restoration costs.

(f) **Stock based compensation plans**

Consideration paid by employees or directors on the exercise of stock options under the employee stock option plan and the purchase of stock under the employee stock savings plan is recorded as share capital. The Company matches employee contributions to the stock savings plan and these cash payments are recorded as compensation expense.

(g) **Income tax**

The Company follows the tax allocation method of accounting for income taxes. Under this method, deferred income taxes are recorded to the extent that taxable income otherwise determined is adjusted by timing differences.

(h) **Revenue recognition**

Settlement payments received for restructuring or terminating long term natural gas sales contracts are recognized as revenue over the remaining period of the contracts or over the life of the reserves associated with the contracts.

(i) **Foreign currency translation**

Monetary assets and liabilities denominated in a foreign currency are translated at the rate of exchange in effect at year end while non-monetary assets and liabilities are translated at historical rates of exchange. Revenues and expenses are translated at monthly average rates of exchange. Translation gains and losses are included in earnings except for unrealized gains and losses on long term monetary items which are deferred and amortized to earnings over their remaining term.

(j) **Hedging**

Amounts received or paid under interest rate swaps are recognized in interest expense on an accrual basis, while gains and losses on exchange rate hedges are included in revenue on the sale of the related production.

(k) **Use of estimates**

Management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reported period. Actual results could differ from these estimates.

2. PROPERTY, PLANT AND EQUIPMENT

	1999 Cost	1999 Accumulated depletion and depreciation	1998 Cost	1998 Accumulated depletion and depreciation
Oil and gas properties, including plant and production equipment	**$ 4,777,716**	**$ (2,436,042)**	$ 4,501,996	$ (2,179,349)
Pipelines	**155,909**	**(53,087)**	150,774	(49,668)
Buildings, land and other	**73,362**	**(47,814)**	65,138	(43,762)
	$ 5,006,987	**$ (2,536,943)**	$ 4,717,908	$ (2,272,779)
Net book value		**$ 2,470,044**		$ 2,445,129

At September 30, 1999, oil and gas properties included $179,000,000 (1998 – $157,000,000) relating to unproved properties which have been excluded from depletion and depreciation calculations. Future development costs of proven undeveloped reserves of $301,662,000 (1998 – $278,869,000) are included in depletion and depreciation calculations.

At September 30, 1999, the Company had a substantial surplus in its ceiling test using year end prices.

3. LONG TERM DEBT

	1999 Balance outstanding	1999 Interest rate (1)	1998 Balance outstanding	1998 Interest rate (1)
Bank loans	**$ 82,334**	**5.36%**	$ 231,717	6.20%
Bank loans subject to swaps	**253,000**	**6.69%**	253,000	6.68%
Oil indexed debentures, maturing October 2000	**200,000**	**8.26%**	200,000	8.26%
9.54% sinking fund debentures, maturing October 2002	**10,800**	**9.54%**	11,700	9.54%
	546,134		696,417	
Less current portion	**(900)**		(900)	
	$ 545,234		$ 695,517	

(1) As at September 30.

The Company has a $500,000,000 syndicated revolving credit facility with an extendible two year revolving period and a six year term period, a $65,000,000 syndicated revolving credit facility due on March 30, 2003 and $62,500,000 in operating lines of credit. Advances under the facilities can be drawn in either Canadian or U.S. funds. The facilities bear interest at the bank's prime lending rate, bankers' acceptance rates plus applicable margins or U.S. libor rates plus applicable margins. The margins vary depending on financial statement ratios and can range from 0.35 percent to 0.90 percent. Loans under the facilities are unsecured.

The Company has fixed the rate of interest on $253,000,000 of its bank loans through swap agreements at an average rate of 6.69 percent. These agreements mature at various dates as shown below:

Amount	Interest rate (1)	Maturity date
$ 35,000	7.11%	September 2001
32,500	6.41%	October 2001
53,000	5.80%	November 2001
7,500	6.55%	October 2002
40,000	7.07%	February 2007
30,000	7.28%	March 2007
30,000	7.07%	June 2007
25,000	6.60%	July 2007
$ 253,000	6.69%	

(1) Includes margin.

The oil indexed debentures bear interest at a fixed rate of 5.00 percent per annum plus a variable rate of up to 16.80 percent per annum based upon the average price of crude oil. The effective rate of interest on the debentures has been fixed to maturity at 8.26 percent by an unsecured interest rate swap agreement.

It is anticipated that the bank loans will be extended and that the debentures will be refinanced. If so, long term debt maturities and sinking fund requirements for the next five years will be $900,000 in 2000, $900,000 in 2001 and $900,000 in 2002.

The Company has unused operating lines of credit of $51,741,000.

4. OTHER CREDITS

	1999	1998
Deferred revenue	$ **70,016**	$ 80,617
Deferred future site restoration costs	**61,069**	48,759
Pension accrual (note 9)	**5,593**	5,647
	$ **136,678**	$ 135,023

At September 30, 1999, the estimated future site restoration costs to be accrued over the life of the remaining reserves were $216,629,000.

5. SHARE CAPITAL

Authorized:

Common shares: unlimited
Preferred shares: unlimited
Junior preferred shares, redeemable, participating: unlimited

Issued:

	1999		1998	
	Number of shares	Amount (thousands)	Number of shares	Amount (thousands)
Common shares				
Balance, beginning of year	**123,260,352**	$ **594,875**	122,360,963	$ 582,836
Issued for cash on exercise of stock options	**2,553,155**	**39,198**	694,207	8,869
Issued for cash under employee stock savings plan	**216,827**	**3,473**	205,182	3,170
Balance, end of year	**126,030,334**	**637,546**	123,260,352	594,875
Contributed surplus		**153,552**		153,552
	126,030,334	$ **791,098**	123,260,352	$ 748,427

The Company has an employee stock option plan under which both employees and directors are eligible to receive grants. On September 30, 1999, 9,626,530 common shares were reserved for issuance under the plan. Options granted under the plan generally have a term of five years to expiry and vest equally over a three year period starting on the first anniversary date of the grant. The exercise price of each option equals the market price of the Company's common shares on the date of the grant. The outstanding options are exercisable at various dates to the year 2004. On September 30, 1999, 7,423,564 options were outstanding under the plan with exercise prices between $10.60 and $19.40, and a weighted-average remaining contractual life of 3.3 years.

	1999			1998		
	Number of options		Weighted-average exercise price	Number of options		Weighted-average exercise price
Stock options outstanding, beginning of year	**7,647,502**	**$**	**15.95**	6,066,176	$	15.42
Granted	**2,595,800**		**14.68**	2,746,600		16.36
Exercised	**(2,553,155)**		**15.35**	(694,207)		12.78
Cancelled	**(266,583)**		**15.93**	(471,067)		16.27
Stock options outstanding, end of year	**7,423,564**	**$**	**15.71**	7,647,502	$	15.95
Exercisable at year end	**2,560,734**	**$**	**15.95**	3,125,100	$	15.32

In 1999, the employee stock option plan was amended to give the Board of Directors the discretion to attach share appreciation rights to stock options granted after February 10, 1999. Share appreciation rights give the holder of the options the right to surrender his options for cancellation and receive a cash payment from the Company equal to the excess of the then current market price of the common shares over the exercise price of the options. To date, no share appreciation rights have been granted.

Under the employee stock savings plan, the Company is authorized to issue shares of common stock to all of its permanent employees. Under the terms of the plan, qualifying employees may contribute from four percent to eight percent of basic annual earnings. Employee contributions are invested in the Company's common shares purchased from treasury at market prices. The Company matches the employees' contributions, investing in qualified money market instruments or additional common shares of the Company purchased on the open market. The Company's share of contributions is recorded as compensation expense and amounted to $3,473,000 in 1999 (1998 – $3,170,000). At September 30, 1999, 1,043,476 common shares were reserved for issuance under the plan.

On August 18, 1999, the Board of Directors adopted a Shareholder Rights Plan to replace the Company's previous plan which expired earlier in the year. The Plan is subject to regulatory and shareholder approval. If a bid to acquire control of the Company is made, the Plan is designed to give the Board of Directors of the Company time to consider alternatives to allow shareholders to receive full and fair value for their shares. In the event that a bid, other than a permitted bid, is made, shareholders become entitled to exercise rights to acquire common shares of the Company at 50 percent of market value. This would significantly dilute the value of the bidder's holdings.

On November 16, 1999, the Board of Directors approved a Notice of Intention to make a Normal Course Issuer Bid, under which the Company may acquire up to five percent of its outstanding common shares through the facilities of The Toronto Stock Exchange.

6. PER SHARE AMOUNTS

Earnings per common share and cash flow from operations per common share are calculated using the weighted average number of common shares outstanding. Fully diluted calculations include imputed interest calculated at a rate of 5.6 percent (1998 – 5.4 percent) on the proceeds from the exercise of stock options, tax effected at statutory rates. Imputed interest is calculated on all outstanding stock options, regardless of whether they have vested or are currently in the money. These calculations resulted in the addition of $3,897,000 (1998 – $3,168,000) and $5,083,000 (1998 – $5,739,000) of interest, after tax, to earnings and cash flow from operations respectively, in calculating fully diluted per share amounts.

7. TAXES

The provision for taxes differs from the result which would have been obtained by applying the combined federal and provincial tax rate to earnings before taxes. The difference results from the following items:

	1999	1998
Earnings before taxes	$ 136,459	$ 59,760
Combined federal and provincial tax rate	44.8%	44.8%
Computed "expected" tax	$ 61,134	$ 26,772
Increase (decrease) in taxes resulting from:		
Royalties and other payments to provincial governments	49,465	42,108
Non-deductible depletion	1,203	2,194
Resource allowance	(49,704)	(38,967)
Income tax rebates and credits	(2,057)	(2,715)
Capital taxes	6,962	6,951
Other	(942)	(1,189)
Provision for taxes	$ 66,061	$ 35,154

Property, plant and equipment with a net book value of $33,080,000 (1998 – $37,277,000) has no cost base for income tax purposes.

8. CHANGE IN NON-CASH WORKING CAPITAL

	1999	1998
Accounts receivable	$ (23,619)	$ 17,294
Inventories	(1,418)	(317)
Accounts payable and accrued liabilities	35,897	(33,099)
Taxes payable	13,411	12,043
	$ 24,271	$ (4,079)

The following cash receipts (payments) have been included in the determination of earnings:

	1999	1998
Dividends received	$ 1,097	$ 125
Interest paid	$ (46,468)	$ (46,918)
Taxes (paid) recovered	$ (10,283)	$ 334

9. PENSION PLANS

The Company has a non-contributory registered defined benefit pension plan. In June 1995, the plan was amended to give active employees an opportunity to opt out of the plan in favour of a defined contribution alternative. Most employees opted out of the plan. These employees and all new employees accrue future benefits based on defined contributions. Employees remaining in the plan continue to accrue benefits under the defined benefit plan. The plan is funded based on independent actuarial valuations. Plan assets are invested primarily in publicly traded equity and fixed income securities. Retirement benefits are based on the employees' years of credited service and salaries during the last years of employment.

The retirement benefit under the registered plan is subject to a maximum pension as determined under the Income Tax Act (Canada). To the extent this limitation applied, supplemental retirement allowances were provided to qualifying employees at the time so that the total retirement benefits were sufficient to provide the annuity that those employees would have been entitled to without the limitation. To support the Company's obligations under the supplemental plan, the Company has issued a letter of credit to the custodian of the supplemental plan.

In August 1997, the Company purchased annuity contracts in respect of all the then retired and deferred vested members of the registered plan. Pension assets were used to purchase the annuities. Projected benefit obligations were reduced to reflect this purchase of annuities.

Based on an actuarial valuation dated September 30, 1999, the status of the plans on that date was:

	1999	1998
Pension plan assets	$ 20,268	$ 19,466
Projected benefit obligations	(8,802)	(7,665)
Excess of pension plan assets over projected benefit obligations	$ 11,466	$ 11,801

In 1999, the Company recorded pension expense of $402,000 (1998 – $404,000).

10. FINANCIAL INSTRUMENTS

(a) Interest rate risk

The Company has entered into fixed rate debt agreements and interest rate swap agreements in order to manage its interest rate exposure on debt instruments. These agreements are described in note 3.

(b) Foreign currency exchange risk

The Company is exposed to foreign currency fluctuations as crude oil and natural gas prices received are referenced to U.S. dollar denominated prices.

(c) Credit risk

A substantial portion of the Company's accounts receivable are with customers and joint venture partners in the oil and gas industry and are subject to normal industry credit risks. Purchasers of the Company's natural gas, crude oil and natural gas liquids are subject to an internal credit review to minimize the risk of non-payment.

The Company is also exposed to credit risk associated with possible non-performance by counterparties to the interest rate swap agreements. The Company believes these risks to be minimal as the counterparties are major financial institutions which have at least an AA credit rating as determined by recognized credit rating agencies.

(d) Fair value of financial instruments

The carrying amounts of financial instruments included in the consolidated balance sheet, other than long term debt, approximate their fair value due to their short term maturity.

The estimated fair values of long term debt and derivative instruments have been determined based on discounted cash flow analysis using current market interest rates for financial instruments with similar maturities.

The carrying values and estimated fair values of long term debt and derivative instruments are as follows:

	1999		1998	
	Carrying value	Fair value	Carrying value	Fair value
Bank loans	$ 335,334	$ 335,334	$ 484,717	$ 484,717
Interest rate swaps on bank loans	$ –	$ 2,396	$ –	$ 11,703
Oil indexed debentures	$ 200,000	$ 199,336	$ 200,000	$ 198,602
Interest rate swap on oil indexed debentures	$ –	$ 6,195	$ –	$ 12,070
9.54% sinking fund debentures	$ 10,800	$ 11,641	$ 11,700	$ 13,103

11. SEGMENTED INFORMATION

The Company operates in Canada in the oil and gas and pipeline transportation industries.

1999	**Oil and gas**	**Pipeline**	**Total**
Revenues, net of royalties	**$ 644,995**	**$ 28,863**	**$ 673,858**
Operating expenses	**(153,613)**	**(12,365)**	**(165,978)**
Depletion, depreciation and site restoration	**(279,231)**	**(4,022)**	**(283,253)**
General and administrative expenses	**(40,684)**	**(720)**	**(41,404)**
Interest	**(42,488)**	**(4,276)**	**(46,764)**
Earnings before taxes	**128,979**	**7,480**	**136,459**
Taxes	**(62,612)**	**(3,449)**	**(66,061)**
Earnings	**$ 66,367**	**$ 4,031**	**$ 70,398**
Cash flow from operations	**$ 387,590**	**$ 8,020**	**$ 395,610**
Net capital expenditures	**$ 283,834**	**$ 5,323**	**$ 289,157**
Total assets	**$ 2,499,710**	**$ 106,505**	**$ 2,606,215**

1998	Oil and gas	Pipeline	Total
Revenues, net of royalties	$ 548,233	$ 27,712	$ 575,945
Operating expenses	(160,471)	(9,840)	(170,311)
Depletion, depreciation and site restoration	(264,551)	(2,771)	(267,322)
General and administrative expenses	(31,576)	(843)	(32,419)
Interest	(43,983)	(2,150)	(46,133)
Earnings before taxes	47,652	12,108	59,760
Taxes	(29,704)	(5,450)	(35,154)
Earnings	$ 17,948	$ 6,658	$ 24,606
Cash flow from operations	$ 296,313	$ 9,724	$ 306,037
Net capital expenditures	$ 476,167	$ 51,491	$ 527,658
Total assets	$ 2,451,328	$ 104,935	$ 2,556,263

12. UNCERTAINTY DUE TO THE YEAR 2000 ISSUE

The Year 2000 Issue arises because many computerized systems use two digits rather than four to identify a year. Date sensitive systems may recognize the year 2000 as 1900 or some other date, resulting in errors when information using year 2000 dates is processed. In addition, similar problems may arise in some systems which use certain dates in 1999 to represent something other than a date. The effects of the Year 2000 Issue may be experienced before, on, or after January 1, 2000 and, if not addressed, the impact on operations and financial reporting may range from minor errors to significant systems failure which could affect an entity's ability to conduct normal business operations. While the Company has a plan to address the Year 2000 Issue, it is not possible to be certain that all aspects of the issue affecting the Company, including those related to the efforts of customers, suppliers, or other third parties, will be fully resolved.

Ten Year Review

	1999	1998	1997	1996
Financial (in millions, except per share amounts)				
Revenues				
Oil and gas	**$ 769.6**	$ 646.6	$ 705.1	$ 569.3
Royalties, net of ARTC	**(125.9)**	(107.7)	(120.4)	(92.6)
Pipeline	**28.6**	27.5	27.4	28.0
Other	**1.6**	9.5	17.5	3.3
	673.9	575.9	629.6	508.0
Expenses				
Operating	**166.0**	170.3	156.6	115.0
Depletion and depreciation	**264.6**	255.4	240.7	219.6
General and administrative	**41.4**	32.4	29.3	28.0
Interest	**46.8**	46.1	36.0	41.4
Future site restoration	**18.6**	11.9	10.4	10.0
Restructuring costs	**–**	–	–	–
	537.4	516.1	473.0	414.0
Earnings (loss) before taxes	**136.5**	59.8	156.6	94.0
Taxes				
Current	**23.7**	11.7	8.5	12.3
Deferred	**42.4**	23.5	60.2	33.5
	66.1	35.2	68.7	45.8
Earnings (loss)	**$ 70.4**	$ 24.6	$ 87.9	$ 48.2
Per common share (basic)	**$ 0.57**	$ 0.20	$ 0.72	$ 0.40
Cash flow from operations	**$ 395.6**	$ 306.0	$ 383.0	$ 306.8
Per common share (basic)	**$ 3.19**	$ 2.49	$ 3.14	$ 2.54
Balance sheet information				
Net additions to property, plant and equipment	**$ 289.2**	$ 527.7	$ 468.7	$ 247.4
Corporate acquisitions (dispositions)	**$ –**	$ –	$ (50.4)	$ –
Long term debt	**$ 545.2**	$ 695.5	$ 545.0	$ 512.7
Working capital (deficiency)	**$ (30.0)**	$ (11.9)	$ (7.7)	$ (13.8)
Shareholders' equity	**$ 1,135.8**	$ 1,022.7	$ 986.1	$ 881.3
Common shares outstanding at September 30	**126.0**	123.3	122.4	121.0
Operating				
Daily sales				
Natural gas (Mmcfd)	**568**	555	549	506
Crude oil (Bpd)	**25,565**	29,808	27,472	24,097
NGL (Bpd)	**8,020**	7,376	5,669	5,489
	33,585	37,184	33,141	29,586
Proven reserves				
Natural gas (Bcf)	**1,812**	1,758	1,768	1,798
Crude oil and NGL (Mmbbls)	**146.0**	148.0	130.9	107.7
Proven plus probable reserves				
Natural gas (Bcf)	**2,699**	2,675	2,713	2,694
Crude oil and NGL (Mmbbls)	**221.7**	225.6	200.3	165.7
Wells drilled for oil and gas				
Gross	**273**	446	669	335
Net	**179**	280	426	210
Employees				
Calgary	**410**	390	347	293
Field	**352**	347	332	329

1995* (pooled)	1995*	1994*	1993*	1992*	1991*	1990*
$ 518.4	$ 230.0	$ 209.0	$ 136.6	$ 94.7	$ 93.6	$ 82.7
(85.6)	(39.2)	(42.9)	(26.1)	(18.1)	(20.8)	(15.0)
26.8	–	–	–	–	–	–
3.4	–	0.1	0.1	0.1	–	6.1
463.0	190.8	166.2	110.6	76.7	72.8	73.8
111.9	42.1	35.2	24.4	20.5	18.6	14.5
209.0	93.2	66.7	42.7	30.5	23.7	19.8
50.4	9.8	8.0	6.2	5.6	4.6	3.5
49.6	13.7	8.3	10.0	10.8	8.3	11.3
8.4	4.4	3.3	2.0	1.5	–	–
36.9	4.1	–	–	–	–	–
466.2	167.3	121.5	85.3	68.9	55.2	49.1
(3.2)	23.5	44.7	25.3	7.8	17.6	24.7
6.8	2.2	1.9	0.9	0.8	5.0	0.9
(4.2)	9.6	18.6	9.4	3.8	6.6	10.6
2.6	11.8	20.5	10.3	4.6	11.6	11.5
$ (5.8)	$ 11.7	$ 24.2	$ 15.0	$ 3.2	$ 6.0	$ 13.2
$ (0.05)	$ 0.21	$ 0.45	$ 0.33	$ 0.08	$ 0.15	$ 0.36
$ 208.3	$ 119.0	$ 112.8	$ 69.0	$ 39.1	$ 36.3	$ 38.2
$ 1.73	$ 2.09	$ 2.09	$ 1.52	$ 0.95	$ 0.89	$ 1.04
$ 322.5	$ 175.6	$ 178.9	$ 81.6	$ 12.5	$ 33.0	$ 72.5
$ –	$ –	$ 70.0	$ –	$ 106.5	$ –	$ –
$ 561.9	$ 153.3	$ 90.5	$ 90.8	$ 152.2	$ 72.7	$ 75.0
$ (20.2)	$ (12.3)	$ (18.0)	$ (11.4)	$ 1.5	$ 1.6	$ 3.4
$ 828.0	$ 421.5	$ 410.7	$ 276.1	$ 196.3	$ 191.8	$ 182.7
120.5	57.2	56.9	49.4	41.4	41.2	40.6
507	282	215	160	111	77	66
25,628	8,606	6,510	4,775	4,131	4,346	3,821
6,253	2,040	1,746	1,182	1,617	1,082	1,162
31,881	10,646	8,256	5,957	5,748	5,428	4,983
1,812	901	900	755	698	619	575
99.2	30.4	29.4	19.4	17.7	15.1	16.4
2,739	1,387	1,378	1,162	1,033	907	872
158.9	46.7	43.9	28.4	25.4	22.3	24.0
308	136	225	157	43	73	105
230	105	172	90	21	54	77
314	105	106	79	65	53	52
347	119	110	79	67	61	53

* In September 1995, a business combination between Anderson Exploration Ltd. and Home Oil Company Limited was accomplished. The business combination was accounted for using the pooling of interests method of accounting. Under this method, the consolidated financial and operating results reflect the historical results of both companies as if they had always been together. This means that the pooled financial and operating results for fiscal 1995 reflect the combined operations of the two companies for that entire year even though the business combination was only accomplished in the last month of the year. Fiscal 1999 is the fourth full year after the business combination. Historical results of Anderson Exploration Ltd. on a stand alone basis have been provided as supplementary information for 1995 and prior years.

Supplementary Information

OIL AND GAS OPERATIONS

	Gas converted to oil at 6 Mcf/Bbl*			Gas converted to oil at 10 Mcf/Bbl*		
	1999	1998	1997	**1999**	1998	1997
Cash Flow from Operations and Earnings per Barrel of Oil Equivalent						
Oil and gas revenues	**$ 16.44**	$ 13.67	$ 15.37	**$ 23.33**	$ 19.12	$ 21.86
Royalties	**(2.69)**	(2.28)	(2.62)	**(3.82)**	(3.18)	(3.72)
Operating costs	**(3.28)**	(3.39)	(3.20)	**(4.66)**	(4.75)	(4.55)
	10.47	8.00	9.55	**14.85**	11.19	13.59
Other revenues	**0.03**	0.01	0.15	**0.04**	–	0.21
General and administrative expenditures	**(0.87)**	(0.67)	(0.71)	**(1.23)**	(0.93)	(1.01)
Interest	**(0.91)**	(0.93)	(0.74)	**(1.29)**	(1.30)	(1.05)
Current taxes	**(0.44)**	(0.14)	(0.04)	**(0.62)**	(0.20)	(0.06)
Cash flow from operations	**8.28**	6.27	8.21	**11.75**	8.76	11.68
Depletion and depreciation	**(5.57)**	(5.35)	(5.21)	**(7.90)**	(7.48)	(7.40)
Future site restoration	**(0.39)**	(0.25)	(0.23)	**(0.56)**	(0.35)	(0.32)
Deferred taxes	**(0.90)**	(0.49)	(1.30)	**(1.28)**	(0.68)	(1.84)
Other	**–**	0.19	0.17	**–**	0.28	0.24
Earnings	**$ 1.42**	$ 0.37	$ 1.64	**$ 2.01**	$ 0.53	$ 2.36
Average daily sales in barrels of oil equivalent	**128,209**	129,599	123,339	**90,360**	92,634	86,739
Natural Gas and NGL Netbacks						
Average sales price ($/Mcf)	**$ 2.49**	$ 2.00	$ 2.04	**$ 2.37**	$ 1.91	$ 1.96
Royalty expense ($/Mcf)	**(0.43)**	(0.35)	(0.34)	**(0.41)**	(0.34)	(0.33)
Operating expense ($/Mcf)	**(0.43)**	(0.37)	(0.32)	**(0.41)**	(0.35)	(0.31)
Cash netback	**$ 1.63**	$ 1.28	$ 1.38	**$ 1.55**	$ 1.22	$ 1.32
Average daily natural gas sales (Mmcfd)	**568**	555	549	**568**	555	549
Average daily NGL sales (Bpd)	**8,020**	7,376	5,669	**8,020**	7,376	5,669
Crude Oil Netbacks						
Average sales price ($/Bbl)	**$ 21.17**	$ 18.57	$ 25.74			
Royalty expense ($/Bbl)	**(3.16)**	(2.92)	(4.92)			
Operating expense ($/Bbl)	**(5.97)**	(7.26)	(7.94)			
Cash netback	**$ 12.04**	$ 8.39	$ 12.88			
Average daily crude oil sales (Bpd)	**25,565**	29,808	26,170			

* The operating statistics presented in this analysis are expressed on a barrel of oil equivalent basis (or thousand cubic foot equivalent basis), using two different conversion ratios. Previously, in Canada, it was common to convert gas to oil at 10 thousand cubic feet per barrel, which approximated historical relative sales value. Outside of Canada, particularly in the United States, it was more common to convert gas to oil at six thousand cubic feet per barrel, which approximates relative heating values. With improved access to U.S. gas markets and the resulting improvements in gas prices, more Canadian oil and gas companies, including Anderson Exploration, as well as analysts in the investment community, are adopting the six thousand cubic feet per barrel ratio.

OIL AND GAS OPERATIONS

	Gas converted to oil at 6 Mcf/Bbl*			Gas converted to oil at 10 Mcf/Bbl*		
	1999	1998	1997	**1999**	1998	1997
Finding and Development Costs						
Current year additions before revisions						
Proven	**$ 4.89**	$ 6.80	$ 6.28	**$ 7.62**	$ 8.84	$ 7.92
Proven plus one half probable	**$ 3.96**	$ 5.74	$ 5.11	**$ 6.15**	$ 7.41	$ 6.49
Current year additions after revisions						
Proven	**$ 5.31**	$ 7.66	$ 6.37	**$ 7.85**	$ 9.62	$ 7.75
Proven plus one half probable	**$ 5.66**	$ 7.44	$ 5.52	**$ 8.40**	$ 9.12	$ 6.71
Three year weighted average after revisions						
Proven	**$ 6.50**	$ 6.47		**$ 8.45**	$ 8.13	
Proven plus one half probable	**$ 6.22**	$ 6.18		**$ 7.96**	$ 7.66	

QUARTERLY RESULTS

Year ended September 30, 1999 ($ millions, except per share amounts)	Q1	Q2	Q3	Q4	Total
Revenue before royalties	**$ 183.0**	**$ 181.6**	**$ 195.6**	**$ 239.5**	**$ 799.7**
Cash flow from operations	**$ 92.4**	**$ 84.9**	**$ 95.7**	**$ 122.6**	**$ 395.6**
Cash flow from operations per common share (basic)	**$ 0.75**	**$ 0.69**	**$ 0.77**	**$ 0.98**	**$ 3.19**
Earnings	**$ 12.9**	**$ 10.5**	**$ 17.0**	**$ 30.0**	**$ 70.4**
Earnings per common share (basic)	**$ 0.10**	**$ 0.09**	**$ 0.14**	**$ 0.24**	**$ 0.57**
Net capital expenditures	**$ 76.2**	**$ 102.6**	**$ 26.7**	**$ 83.7**	**$ 289.2**
Daily sales					
Natural Gas (Mmcfd)	**559**	**558**	**570**	**584**	**568**
Crude Oil (Bpd)	**26,677**	**25,943**	**24,909**	**24,733**	**25,565**
NGL (Bpd)	**8,241**	**8,837**	**6,774**	**8,232**	**8,020**
	34,918	**34,780**	**31,683**	**32,965**	**33,585**

Year ended September 30, 1998 ($ millions, except per share amounts)	Q1	Q2	Q3	Q4	Total
Revenue before royalties	$ 195.2	$ 163.5	$ 164.1	$ 160.9	$ 683.7
Cash flow from operations	$ 90.8	$ 65.1	$ 67.7	$ 82.4	$ 306.0
Cash flow from operations per common share (basic)	$ 0.74	$ 0.53	$ 0.55	$ 0.67	$ 2.49
Earnings	$ 11.3	$ (2.6)	$ 5.7	$ 10.2	$ 24.6
Earnings per common share (basic)	$ 0.09	$ (0.02)	$ 0.05	$ 0.08	$ 0.20
Net capital expenditures	$ 214.7	$ 159.6	$ 95.2	$ 58.2	$ 527.7
Daily sales					
Natural Gas (Mmcfd)	561	554	545	558	555
Crude Oil (Bpd)	30,700	31,062	29,046	28,441	29,808
NGL (Bpd)	6,529	8,731	6,948	7,320	7,376
	37,229	39,793	35,994	35,761	37,184

Corporate Information

BOARD OF DIRECTORS

J. C. Anderson
(1968)
Chairman & Chief Executive Officer
Calgary, Alberta

Ian D. Bayer (1)(3)(4)
(1984)
Corporate Director
Houston, Texas

W. Gordon Brown, Q.C. (2)
(1982)
Partner
Bennett Jones
Calgary, Alberta

E. Susan Evans Q.C. (1)(4)
(1995)
Corporate Director
Calgary, Alberta

J. Richard Harris (2)(3)
(1988)
Oil & Gas Consultant
Calgary, Alberta

Charles J. Howard (1)(4)
(1993)
President & Chief Executive Officer
Ausnoram Holdings Limited
Toronto, Ontario

(1) Member of Audit Committee
(2) Member of Compensation Committee
(3) Member of Reserves Committee
(4) Member of Governance Committee
(Fiscal year first elected as Director)

CORPORATE OFFICERS

J. C. Anderson
Chairman & Chief Executive Officer

Brian H. Dau
Executive Vice President & Chief Operating Officer

David G. Scobie
Senior Vice President & Chief Financial Officer
Treasurer

Henry H. Assen
Vice President, Marketing

Fred E. Baker
Vice President, Exploration

Dan F. Kell
Vice President, Land

W. A. (Drew) Livingston
Vice President, Production

Richard C. Osborne
Vice President, Pipelines

Gerald S. Read
Controller

R. Vance Milligan
Partner, Bennett Jones
Secretary

MANAGERS

Business Development

Department Head
Sam A. Coles

Exploitation

Department Head
Phil A. Harvey

Area Managers
Scot Collins
Brian G. Kergan
Greg J. Kuran
Paul E. Vigneau

Exploration

Area Managers
Steve J. Babcock
Frank J. Gratton
Ron A. Lambie
Al J. Onia
Tim B. Watters

Geophysical Operations
Ken B. Robinson

Finance

Finance
M. Darlene Wong

Office Services
Linda M. Ellergodt

Operations Accounting
George R. Nichols

Land

Land & Contract Administration
Lynn M. Gregory

Land Negotiations
Sandy M. Drinnan

Marketing

Natural Gas
Keith J. Fardy

Liquids
Josie M. MacGillivray

Operations

Department Head
Kevin L. Stashin

Drilling
Carl F. Hiscock

Completions
Jim N. Peta

Production Engineering
Pat G. Bell
Phil G. Hyde
Tom J. Negenman

Production

Facilities
Doug N. Whiteside

Production
Jan H. Olthof

Safety & Environment
Walter C. Tersmette

Pipelines

Business Development
Dave M. Spyker

Engineering
Dayle W. Chadbourne

Operations
Burdette M. Lehne

Shipper Services & Accounting
Chris I. Grayston

District Superintendents

Carstairs, AB
Terry J. Clelland

Fairview, AB
Ron L. Strandquist

Fort St. John, BC
Tip C. Johnson

Lloydminster, AB
Doug J. Moore

Swan Hills, AB
Bill N. Crossman

Head Office

Suite 1600
324 Eighth Avenue S.W.
Calgary, Alberta T2P 2Z5
Telephone (403) 232-7100
Fax (403) 232-7678

Web Site

www.axl.ca

Field Offices

Carstairs, Alberta
Fairview, Alberta
Fort St. John, B.C.
Lloydminster, Alberta
Swan Hills, Alberta

Auditors

KPMG LLP
Calgary, Alberta

Solicitors

Bennett Jones
Calgary, Alberta

Independent Engineers

Gilbert Laustsen Jung Associates Ltd.
Calgary, Alberta

Registrar & Transfer Agent

Montreal Trust Company of Canada
Calgary, Vancouver, Regina, Winnipeg, Toronto, Montreal, Halifax

Stock Exchange

The Toronto Stock Exchange
Symbol: AXL

Annual Information Form

Copies of the Company's Annual Information Form are available on request.

Corporate Governance

Information concerning the Company's corporate governance is presented in the Notice of and Information Circular for the Annual and Special Meeting of Shareholders dated January 4, 2000.

Volume Reporting

All production, sales and reserve statistics are Anderson Exploration's working interest amounts before deduction of royalties, unless stated otherwise. Where volumes are reported in barrels of oil equivalent, gas is converted to oil at six thousand cubic feet per barrel unless otherwise noted. This conversion ratio approximates relative heating values. In previous years, 10 thousand cubic feet per barrel was used as an approximation of historical relative sales values. But with improved access to U.S. gas markets and the resulting improvement in gas prices, more Canadian oil and gas companies and analysts in the investment community are adopting the six Mcf/Bbl ratio. The six Mcf/Bbl ratio is also more common outside of Canada, particularly in the United States. For transitional purposes, many key financial and operating statistics have also been calculated using the 10 Mcf/Bbl ratio and are provided as supplementary information on pages 58 and 59 of this annual report.

Financial Reporting

All amounts are in Canadian dollars, unless stated otherwise. The Company's fiscal year end is September 30.

Abbreviations Used In Annual Report

Bbl	barrel(s)
Bcf	billion cubic feet
Bpd	barrels per day
Boe	barrels of oil equivalent
Mbbls	thousand barrels
Mcf	thousand cubic feet
Mcfd	thousand cubic feet per day
Mmbbls	million barrels
Mmcfd	million cubic feet per day
NGL	natural gas liquids

Metric Conversion

To Convert From	*To*	*Divide by*
Thousand cubic feet (Mcf) gas	Thousand cubic metres (10^3m^3)	35.4937
Barrels (Bbls) oil	Cubic metres (m^3)	6.2898
Feet (well depths)	Metres (m)	3.2808
Miles (distance)	Kilometres (km)	0.6214
Acres (land)	Hectares (ha)	2.5000

Designed and produced by Parallel. Printed in Canada. This report contains a minimum of 20% post-consumer recycled fibre.

ANDERSON EXPLORATION LTD.
Suite 1600, 324 Eighth Avenue S.W.
Calgary, Alberta T2P 2Z5